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TECHNOECONOMIC EVALUATION OF FLARED NATURAL GAS REDUCTION AND ENERGY RECOVERY USING GAS-TO-WIRE SCHEME

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Supervisor: Professor Pericles Pilidis

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Abstract

Most mature oil reservoirs or fields tend to perform below expectations, owing to high level of associated gas production. This creates a sub-optimal performance of the oil production surface facilities; increasing oil production specific operating cost. In many scenarios oil companies flare/vent this gas. In addition to oil production constraints, associated gas flaring and venting consists an environmental disasters and economic waste. Significant steps are now being devised to utilise associated gas using different exploitation techniques. Most of the technologies requires large associated gas throughput.

However, small-scale associated gas resources and non-associated natural gas reserves (commonly referred to as stranded gas or marginal field) remains largely unexploited. Thus, the objective of this thesis is to evaluate techno-economic of gas turbine engines for onsite electric power generation called gas-to-wire (GTW) using the small-scaled associated gas resources. The range of stranded flared associated gas and non-associated gas reserves considered is around 10 billion to 1 trillion standard cubic feet undergoing production decline.

The gas turbine engines considered for power plant in this study are based on simple cycle or combustion turbines. Simple cycle choice of power-plant is conceived to meet certain flexibility in power plant capacity factor and availability during production decline. In addition, it represents the basic power plant module cable of being developed into other power plant types in future to meet different local energy requirements.

This study developed a novel gas-to-wire techno-economic and risk analysis framework, with capability for probabilistic uncertainty analysis using Monte Carlo simulation (MCS) method. It comprises an iterative calculation of the probabilistic recoverable reserves with decline module and power plant thermodynamic performance module enabled by Turbomatch (an in-house code) and Gas Turb® software coupled with economic risk modules with

@Risk® commercial software. This algorithm is a useful tool for simulating the interaction between disrupted gas production profiles induced by production decline and its effect on power plant techno-economic performance over associated gas utilization economic life. Furthermore, a divestment and make-up fuel protocol is proposed for management of gas turbine engine units to mitigate economical underperformance of power plant regime experienced due to production decline.

The results show that utilization of associated gas for onsite power generation is a promising technology for converting waste to energy. Though, associated gas composition can be significant to gas turbine performance but a typical Nigerian associated gas considered is as good as a regular natural gas. The majority of capital investment risk is associated with production decline both natural and manmade. Finally, the rate of capital investment returns decreases with smaller reserves.

Keywords: small-scaled flared associated gas utilization, combustion gas turbines; onsite power generation; associated gas production decline; power plant operations alternatives, gas turbines unit divestment; makeup –fuel, uncertainty analysis

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Nomenclature

GTW	Gas-to-wire
Mboe/d	Million barrels of oil equivalent per day
Bcm/y	Billion cubic meter per year
EUR	Estimated ultimate recovery
GWP	Global warming potential
NGLs	Natural gas liquids
mscfd	Thousand standard cubic feet per day
WI	Wobbe index
PEC	Purchased equipment cost
LPG	Liquefied petroleum gas
URR	Ultimate reserve recovery
MMSCF	Million Standard Cubic Feet
Bcf	Billion cubic feet
Tcf	trillion cubic feet
MMSTB	Million Stock Tank Barrel
SOX	Oxides of Suphur
UR	Ultimate Recovery
APG	associated petroleum gas
AG	Associate gas
FDP	Field Development Plan
TREA	Techno-economic, environmental and Risk Assessment
LNG	Liquefied natural gas
Pn	n percentile
CNG	compressed natural gas
GTL	Gas-to-liquid
NGH	natural gas hydrates
GTS	Gas-to-solid
GTP	Gas-to-products
MCS	Monte Carlo simulation
NPV	net present value

TCI	Total capital investment
IRR	internal rate of return
PBT	pay-back time
CoE	cost of electricity
DCE	decline curve equation
DCA	decline curve analysis
CEA	Chemical Equilibrium with Application
CHP	combined heat and power
CT	Combustion Turbine
DCA	decline curve analysis
DP	design point
EOR	Enhance oil recovery
EGF	Exhaust gas flow
EGT	Exhaust gas temperature
EHV	extrahigh voltages
FHV	Fuel heating value
GTW-CTRA	Gas to wire combined techno-economic and risk analysis
GT	Gas turbine
GOR	gas-oil ratio
HPC	High pressure compressor
HPT	High pressure turbine
HVAC	high voltage alternating current
HVDC	High voltage direct current
d_i	initial decline rate
q_i	initial flow rate at
$q_{(T)}$	instantaneous flow rate
LCV	low calorific value
LPC	Low pressure compressor
MCS	Monte Carlo simulation
NGCC	natural gas combined cycle
OD	off-design
OECD	Organisation for Economic Co-operation and Development

OGIP	original gas in place
OPR	Overall operating pressure
PT	Power turbine
ROW	right-of-way
SFC	Specific fuel consumption
CP	specific heat capacity constant pressure
S-EOR	steam Enhanced Oil Recovery
TRR	technically recoverable reserves
TET	turbine entering temperature
UHC	unburned hydrocarbon
GTW	Gas-to-wire
Mboe/d	Million barrels of oil equivalent per day
2P	proven + probable reserves
3P	proven + probable + possible reserves

Chapter 1

General Introduction

1.1 Research Rationale

The increase in oil exploration and drilling activities yields more associated gas (AG). A raw natural gas released during most oil production. This can be a dissolved (solution) gas or a cape gas occurring in most oil reservoirs. AG is also known as associated petroleum gas (APG) and is estimated to be about 17% of global gas reserves with majority of this gas occurring in small scale [1]. Combination of factors like high cost of gas processing infrastructure, low quantity of discovered gas in a reservoir, relatively low gas price or absent of local market for the gas, and unduly inconsistent government policies often drive the oil producing company to flare or vent APG encountered during oil production [2]. A number of new technologies have evolved to explore options for the commercialization of this abundant energy reserves but success is still on the large gas reserves with most of the smaller (or so-called stranded and marginal field) reserves still remaining unexploited.

Conversely, with emergent stringent regulation on associated gas flaring and re-injection coupled with subsequent global demand to meet growing natural gas energy share begs for stranded associated gas exploitation. Hence, techno-economic and risk assessments of technologies for exploitation of relatively smaller gas reserves is needed. It is envisaged that the result of this assessment will see immediate use in policymaking to improve APG utilisation policies and regulations. This will contribute in reducing the environmental pollutions from gas flaring and venting; whilst serving as a predictive tool for both oil producers and investors interested in investing on APG monetization to insure a fair return on their investment.

1.1.1 Problem Statement

A combined techno-economic and risk assessment framework for the evaluation of onsite conversion of stranded gas to electric power is developed. This will form part of Techno-economic, environmental and Risk Assessment (TREA) framework for associated gas utilization (monetization). The drive to monetise stranded associated gas and marginal gas field reserves for electricity generation—"Gas-To-Wire (GTW)" has been conceived [3-11]. Factors like low carbon content of natural gas compared to other fossil fuels; relatively shorter commissioning time of gas-fired power plant; flexibility of gas turbine engines and growing number of distributed power generation due to deregulation in electric industries have increased the use of natural gas for power generation. An option that favours the concept of small-scale stranded gas reserves exploitation for GTW utilization.

However, due to production decline observed during oil and gas production, GTW monetization is anticipated to be increasingly risky with uncertainty of fuel supply. This increases the dimension of uncertainty in technology and economics of GTW monetization. Triggering questions like: what is the amount of recoverable gas reserves (in terms of 2P: proven + probable reserves or P50, 3P: proven + probable + possible reserves or P10) from proved reserves (1P or P90); what is the number of years to achieve pay-out to recover the initial investment with reduction in initial power plant output capacity as gas supply declines in each case within P10, P50 and P90.

Comparing power generation technology where resource decline affects the capacity and output of the produced power would be a geo-thermal power plant. However in a geo-thermal power plant, effect of declining could be managed by adopting the option of make-up drills. Similarly, it is conventionally easier to upgrade power plant capacity if more energy is required or peak-load unit would be sufficient to argument occasional power increase requirements; rather is arguably difficult to downgrade the output of already built power plant without compromising returns on its investment.

Typical examples of such fields where APG exploitation options have experienced changes in technology in terms of capacity reduction during utilization or monetization due to production decline include: The UK's Magnus Field [12] and the Indonesia's Kaji-Semoga Field [13].

1.2 Research Objectives and Methodology

Oil and gas producers, governments and power companies are all looking to evolve an efficient way to stop APG flaring to harness its energy and increase natural gas energy share. Perhaps, the advent of Liquefied natural gas (LNG) and subsequent developing of compressed natural gas (CNG) technologies will bring a huge success in utilization of large-scale APG resources. However, significant concern is now shifted to the exploitation of APG and stranded small-scale natural gas reserves. The small-scale stranded gas and APG resources production intricacies/uncertainties like production decline, introduces a techno-economic constraints and requires a proper techno-economical assessment for its commercialisation to understand the "what if scenarios" to ensures a fair return on its investment.

The aim of this research is to evaluate the techno-economic of gas turbine engines for onsite power generation as a requirement for GTW monetisation of flare APG and stranded gas resources between 10 billion to 1 trillion scf subjected to a production decline.

The objectives of the work described in this thesis are as follows:

» To initialize development of a novel framework for evaluation of GTW monetisation of small-scale stranded natural gas, mainly APG resource with production decline.

» To assess how natural gas reserves production decline and uncertainties will affect the techno-economic of its GTW monetization using simple cycle or combustion turbine power plant.

- To illustrate the benefit of the proposed approach using selected case studies. Providing basis for discussion about the commercialization of small-scale stranded gas and APG resources, comparing techno-economic of GTW monetization of small-scale gas reserves with other monetization technologies.

In order to achieve these objectives, a GTW-CTRA (Gas to wire combined techno-economic and risk analysis) framework has been developed with capability for probabilistic analysis using Monte Carlo simulation (MCS) techniques. This tool comprises of the probabilistic reserves with decline model and power plant thermodynamic performance model coupled with economic and risk analysis modules. The GTW evaluation case studies are carried out using three different gas reserves scenarios. The economic performance index uses net present value (NPV), internal rate of return (IRR) and pay-back time (PBT) valuation methods.

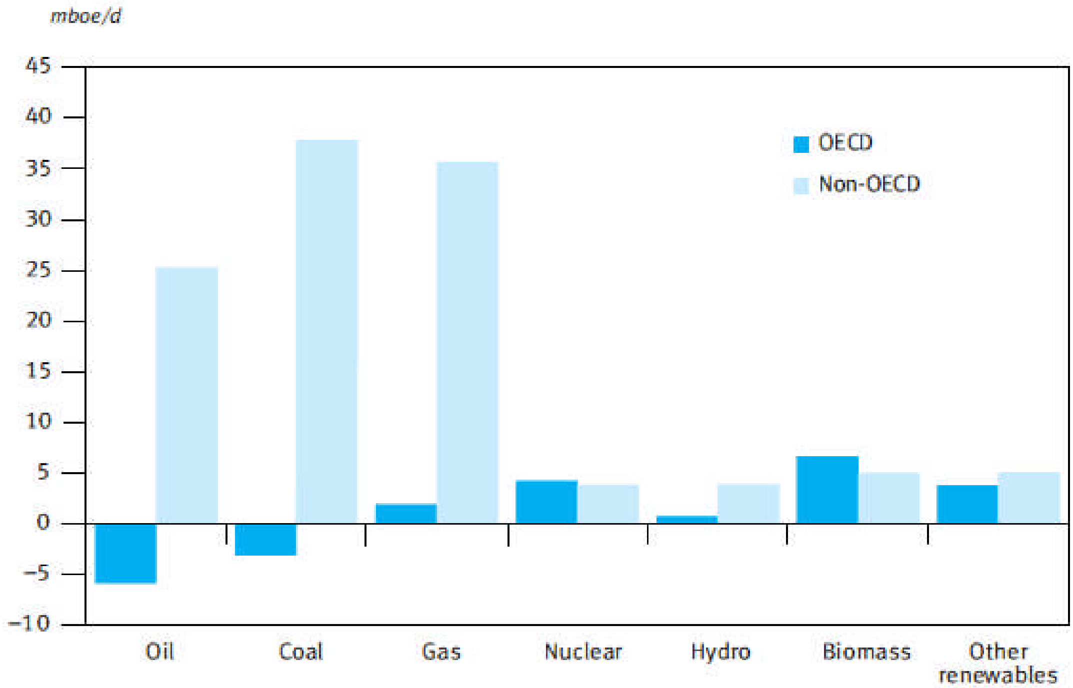
A divestment protocol is proposed for management of gas turbine engine units to mitigate economical underperformance of power plant regime experienced due to reserves declining. Simple cycle or combustion turbine choice of power-plant is conceived to meet certain flexibility in plant capacity availability during production/reserves decline. At end of the evaluation process, an optimisation process is carried out to determine the engine-unit-mix matrices for two reasons. The first is to optimize power plant size during plant underperforming regime and secondly, to balance the investment in facility against gas production level.

1.3 Thesis Contribution

The main contributions of the present work to knowledge include the development of prediction tool for onsite associated gas utilization on gas turbine engine capable of capturing the associated gas composition, recoverable quantity of this gas and its production schedule to ascertain the cost of electricity (CoE) of this process. In addition, it also proposes the borders of economic factors to ensure project viability when utilizing associated gas on gas turbines for power generation called (GTW). A first account of this GTW model has therefore been developed to present an outlook in terms of engine performance, economics and the associated gas utilization investment risk limits.

1.4 Review of Natural Gas Global Energy Share

AGP is abundant in most oil fields in the world, for instance in Nigeria alone, about 60% of estimated natural gas reserves is associated gas [14]. In 2007 annual APG production in Russia was estimated about 73 Bcm/y, accounting about 10% of its annual gas production [12]. Reporting world energy share by fuel type and future projections [15], predicted gas energy share will increase from 23% to 25% between 2010 and 2035. Natural gas is the only fossil fuel with growing energy share, whereas other fossil fuels energy share are declining, especially in the OECD (Organisation for Economic Co-operation and Development) countries as predicated in Figure 1-1 below. This could be attributed to affordable gas price, its low carbon emissions compare to other fossil fuels, and the breakthrough in unconventional gas production like the shale gas.



[1]

Figure 1-1: Energy Demand by Fuel Type, 2010- 2035 [15]

The increase use of natural gas in power generation plants for both base load and peak load applications have generally changed the power generation industry. In the US, drop in gas price has been estimated to reduce the cost of electric production up to 50% [16]. However, to meet the expected growth in world gas consumption by 2035 about 60 trillion cubic feet (Tcf) increase would be required—exceeding 50% increase in supply from 2008 to 2035 [17]. Though, there is a rapid growth of unconventional natural gas discoveries especially in the OECD countries; but there is a great concern with the uncertainty associated with their future production cost and environmental concerns with their extraction process.

[1] Based on Society of Petroleum Engineers definition, boe (barrel of oil equivalent) contains 6.5 to 7.9 toe (tonnes oil equivalent) and toe = 41.868 GJ.

1.5 Associated Gas Production

Associated gas[2] is the dissolved gas contained in oil reservoir at high pressure or a cap gas residing above the oil reservoir which separates at the surface during oil production. Most mature oil fields or reservoirs tend to perform below expectations, owing to high level of associated gas production [18]. This is a great concern for oil producing companies as it could slowdown oil production in some cases. It creates a sub-optimal performance of the surface facilities; increasing specific production cost. In many scenarios oil producers flare/vent this gas or sometimes re-inject them for production recovery. Monitoring oil producing well for gas-oil ratio (GOR) traditionally becomes one of the performance indicators for oil well/reservoir performance.

The commercialisation or monetization of APG requires reliable forecasting of APG production from oil production rate. Estimation of APG production from producing well can be done with the knowledge of the gas-oil ratio (GOR), oil production rate, experience of field/reservoir history and characteristics [12], as depicted in Figure 1-2 below. In practice, two primary factors can affect the rate of APG production: amount of dissolved gas in the oil and the rate of oil production [19]. In order to establish the capacity of GTW (onsite power plant) monetization facility, the amount of technically recoverable reserves (TRR) in addition to economical recoverable resources (ERR) must be calculated from original gas in place (OGIP). Since reserves cannot be measured directly during the life of the reservoir, is usually estimated [20].

[2] Associated gas (AG or APG) reserves as used throughout this thesis is the quantity of gas produced as oil is produced, including dissolved gas reserves.

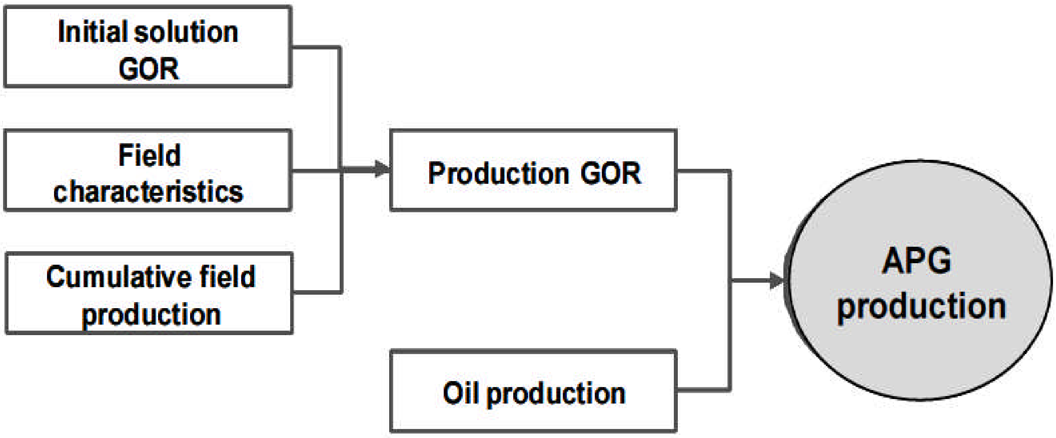
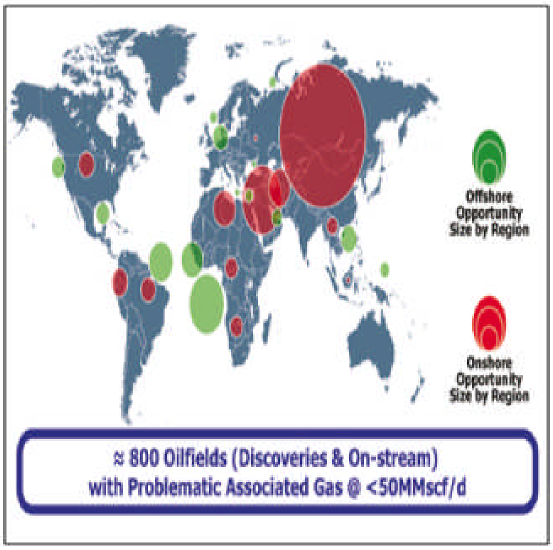
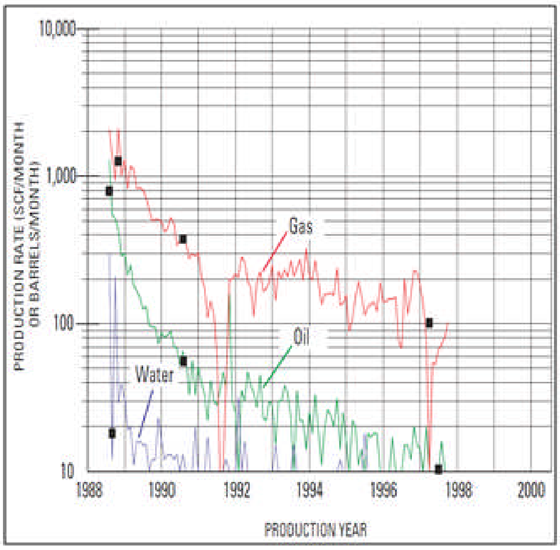


Figure 1-2: Estimation of Associated Gas Production [12]





(I) (II)

Figure 1-3: (I)—World Associated Gas Distribution [21] and (II)—Oil, Gas, and Water Production Data from a Well [22]

Whereas there is no single definition of reserve size, estimation of reservoir size or field reserves comes with a high level of uncertainty. Generally, industries report the amount or size of discovery using different probabilities to include: proved reserves, probable reserves and possible reserves [23]. This reflects different levels of uncertainties; showing high level of contributions by unresolved and unknown fundamental quantities. The problem associated with these probabilistic notations of extracting an estimated volume and their uncertainty includes their unknown probability distribution shapes. This will be detrimental to the techno-economic assessment of GTW monetisation of APG and needs to be taken cognisance of during project evaluation phase.

The inconsistency in defining and reporting of estimated petroleum resources and effort to standardise them started in 1930s [24]. These definitions and classifications have received attention internationally over the years. The target is to provide a measure of comparability and to reduce the subjective nature of resources estimation. Figure 1-5 below shows some recorded progress of different recognised organisations to improve estimation and reporting standards of petroleum resources adapted from [24]. In the SPE/WPC/AAPG/SPEE resource classification framework, ERR and TER was not formally classified. However is important to note that the ERR and TER classifications are functions of time. For the explanation of terms in 2007 resource classification framwork in

Figure 1-4 below and general definition of terms see Appendix A.1.

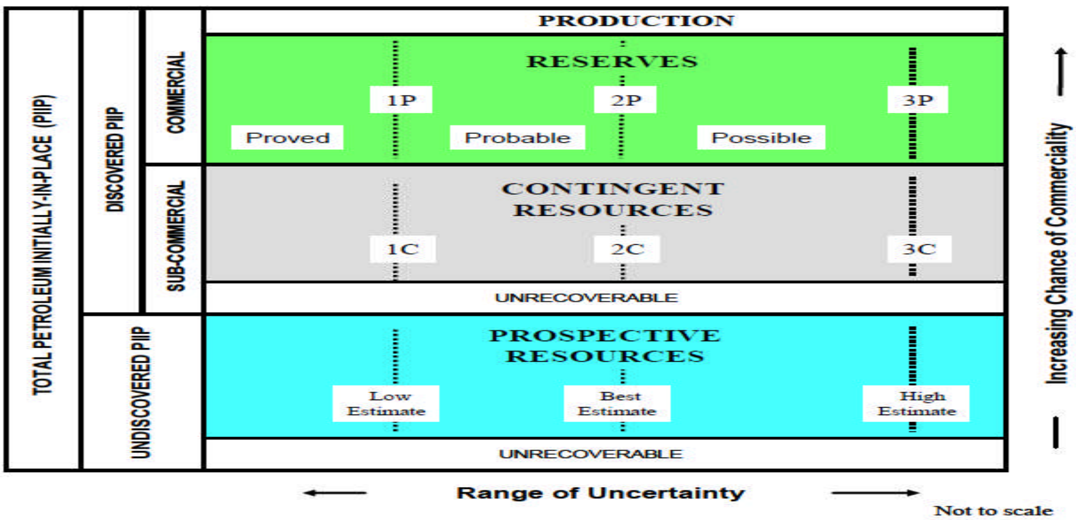


Figure 1-4: SPE/WPC/AAPG/SPEE Resource Classification Framework [24]

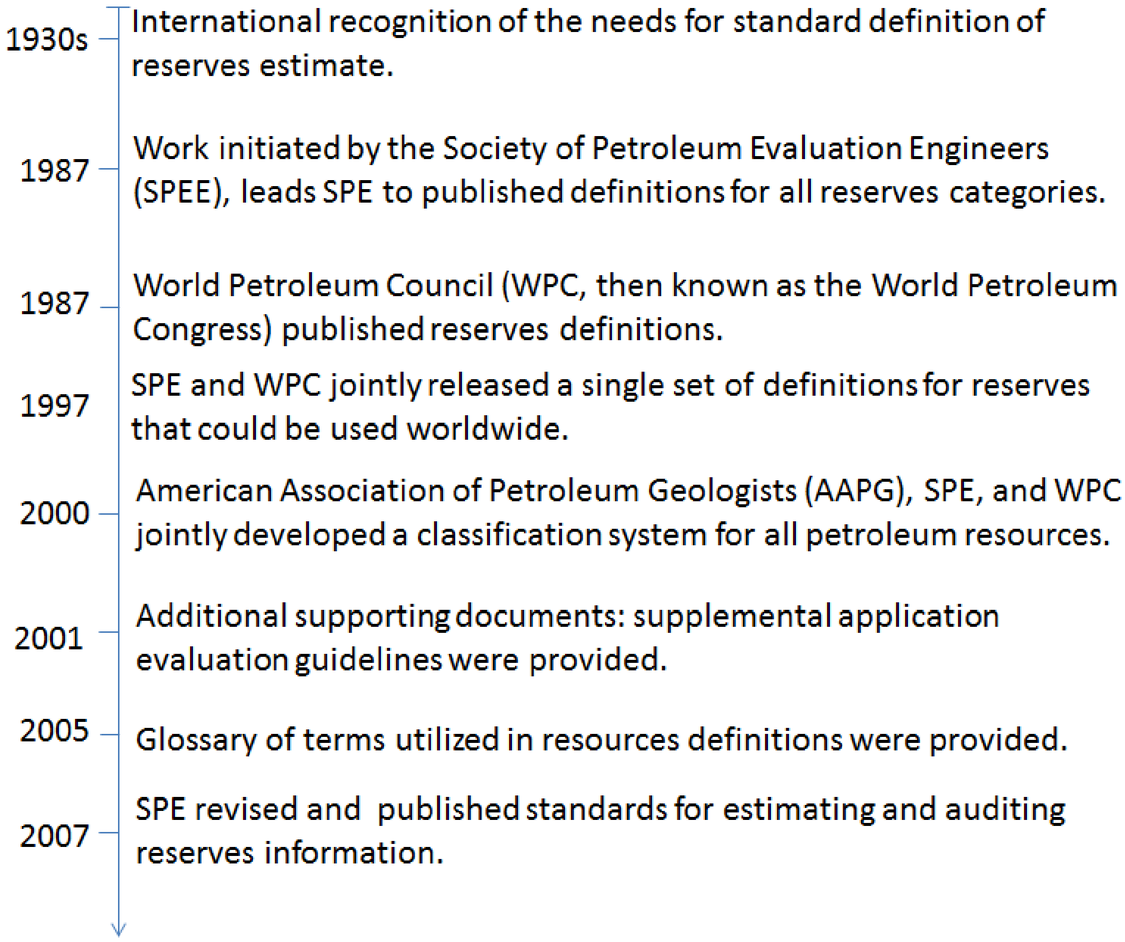


Figure 1-5: Effort to Standardise Definition of Petroleum Resources

1.6 Stranded Natural Gas and Associated Gas Flaring

Proven gas reserve can be classified as stranded reserve when the techno-economic of its conventional production is not favourable by market price. Many literatures including [25] and [4] suggest that stranded natural gas account for more than half of the global proven natural gas reserves. Most of which are APG resources and unconventional gas resources. Limitations of the traditional techniques to harness stranded natural gas vary from lack of facilities, distance to market, terrain, demand, and size of reserve among others.

Perhaps, stranded natural gas from gas reservoir (or non-associated gas) can be extracted once feasible technology for their production and market for such gas exist. Unlike the APG—a co-product (or often seen as a by-product) of oil production, control over its production is tied to oil production. Certain conditions (like the high cost of production facilities) leave the oil producer with little or no option than flaring/venting them. With the exception of quantities re-injected to enhance oil production. Oil producers are looking for cost effective and robust ways to dispose stranded APG to maximise oil production and prevent production shutdown [18].

Continuous flaring and venting of APG, in turn constitutes a major concern to our environment, a huge energy ravage, and a major greenhouse gas emission donor. A report from [6] reveals that in 2010 associated gas flaring alone contributed 30% of global greenhouse emissions. Regrettably most of the regions where this flaring occurs have been experiencing erratic and short supply of electricity, especially the oil-rich developing nations. For instances, Nigeria has been rated the second highest gas flaring country in the world after Russia [26], but generates less than 4600MW electricity, which is less than 50% of estimated power requirement of the country.

Gas flaring in general has grown from been a local problem to a global concern. Venting is even more dangerous since APG is rich in methane which has a high global warming potential (GWP[3]) of 23 over 100 years against GWP of 1 for CO_2 over same period of time. Several policies from government agencies at different level is making it difficult for oil producing companies to flare or vent APG to the atmosphere; as well instigating stringent regulations on gas re-injection knowing that this gas will eventually be reproduced afterwards. For instance, World Bank in 2002 summit for sustainable development in Johannesburg South Africa lunched Global Gas Flaring Reduction (GGFR) Initiative program to tackle the global gas flaring.

The annual global natural gas flaring has been estimated about 150 billion cubic meters [26; 27]. Gas flares statistics from National Oceanic and Atmospheric

[3] *Global warming potential (GWP) is a relative measuring scale, used in comparing global warming contribution of any given mass of greenhouse gas to equivalent mass of CO_2.*

Administration (NOAA) satellite data 2006 - 2010 [26], is shown in Table 1-1 below. Apparently any effort to reduce this wasteful/flaring of non-renewable energy reserves would yield multiple benefits—sustainable energy growth, increase natural gas energy share, reduced greenhouse gases, minimised environmental impact, and increased revenue from associated natural gas resources.

Table 1-1: Estimated Flared Volumes NOAA Satellite Data, 2006-2010 [26]

		Estimated flared volume (billion cubic meter)					
	Country	2006	2007	2008	2009	2010	change from 2008 to 2010
1	Russia	50.0	52.3	42.0	46.6	35.2	11.4
2	Nigeria	18.6	16.3	15.5	14.9	15.2	0.3
3	Iran	12.2	10.7	10.8	10.9	11.3	0.4
4	Iraq	7.2	6.7	7.1	8.1	9.1	1.1
5	Algeria	6.4	5.6	6.2	4.9	5.4	0.5
6	Angola	4.0	3.5	3.5	3.4	4.1	0.7
7	Kazakhstan	6.2	5.5	5.4	5.0	3.8	1.2
8	Libya	4.4	3.8	4.0	3.5	3.8	0.3
9	Saudi Arabia	4.2	4.2	4.3	3.9	3.7	0.2
10	Venezuela	2.1	2.2	2.7	2.8	2.8	0.0
11	Mexico	2.1	2.7	3.6	3.0	2.5	0.5
12	Indonesia	3.2	2.6	2.5	2.9	2.3	0.6
13	China	2.9	2.6	2.5	2.4	2.1	0.3
14	Canada	1.7	2.0	1.9	1.8	2.1	0.3
15	USA*	2.0	2.1	2.3	2.0	2.1	0.1
16	Uzbekistan	2.9	2.1	2.7	1.7	1.9	0.2
17	Qatar	2.3	2.4	2.3	2.2	1.9	0.3
18	Oman	2.3	2.0	2.0	1.9	1.8	0.1
19	Malaysia	1.9	1.8	1.9	1.9	1.5	0.4
20	Egypt	1.7	1.5	1.6	1.8	1.5	0.3
	Total top 20	138	133	125	126	114	11.8
	Rest of the world	23	21	22	21	20	1.1
	Global flaring level	162	154	146	147	134	12.9

*Coverage limited to Gulf of Mexico, Alaska, and partial continental USA

In most cases in some countries oil producing company involved in flaring are required to pay penalties for flaring associated gas at wellhead. These penalties oil producers pay for flaring is not enough to stop them from flaring. Instead flaring continues to be predominating, since oil companies involved in flaring prefer to pay the fines like in the Nigerian case [7]. This act and the lack of inconstancy in accounting for the exact amount of the flared gas volume become another concern. On the other hand government feels threatened and cannot continue to increase the flaring tax because oil production constitutes major source of foreign earning.

1.7 Thesis Structure

This thesis is the first account of the on-going research within the department initiated to exploit small-scaled associated gas throughput during oil production for onsite power generation using gas turbine engines. It consists of seven chapters as follows:

- **Chapter 1** focus on the background of associated gas production and long term effects of flaring/venting on humans, environment and oil production. It explains the rationale and main objective of this study while stating the contribution of the current research. Technology for associated energy utilization is presented. The role of GTW utilization of associated gas is introduced. The roles of natural gas to regional and global economy for future energy mix is outlined and compared with other fossil-fuels.

- **Chapter 2** explains the GTW method as proposed in this research. Covering technical details of the various components of the GTW algorithm. Type and technical reason behind the power plant choice for this research is covered. Summary of literature supporting different associated gas utilization technologies consideration is presented. Literature review to cover the technical aspect of using associated gas as fuel for gas turbine engines. This included the associated gas processing and consequence of gas composition for gas turbine fuel. The technical and economic considerations for power generation is reviewed and extended to electricity transmission economics.

- **Chapter 3** presents a whole synthesis and detailed modelling and testing of the individual components forming the GTW evaluation framework. The description of the eight gas turbine engines that form the engine library for this study and considerations leading to their selection. Associated gas fuel input files for gas turbine simulation is created. The gas turbine engine units are modelled and validated with pure natural gas. Simulation of the associated gas on the gas turbines and its performance is compared with the pure natural gas performance. The associated gas reserve module is generated to establish a production profile. The economic and probabilistic tools were incorporated into the GTW framework.

- **Chapter 4** models a hypothetical associated gas production profile into three scenarios of different reserves sizes to replicate a throughput within this study for GTW techno-economic analysis. This chapter produce results for analyses of technical option of power plant operations during production decline. It also covers analysis of impact of associated gas recoverable reserves on GTW utilization investment.

- **Chapter 5** is application of power plant operational techniques during associated gas production decline phase to improve returns on the investment. Two power plant operational alternatives for production decline mitigations are implanted and evaluated. The advantages and disadvantages of each operational technique are discussed.

- **Chapter 6** applied the proposed GTW framework to Jones Creek Field to evaluate the practicability of the proposed GTW algorithm. This incorporated all the ideas to evaluate what would have been the outcome of deploying gas turbine engines to utilize the associated from that field. The production profile imposed by oil price drop is evaluated in terms of power plant operational techniques.

- **Chapter 7** presents the conclusion of the thesis, and open areas for research relevant to onsite gas turbine utilization of associated gas are discussed. These have the potential to improve the methodology of GTW scheme formulated in this research. It also will improve the investment in this area, reduce associated gas flaring while increasing natural gas energy share.

Chapter 2

GTW Utilization Scheme: General Overview

2.1 Introduction

Gas-to-Wire (GTW) monetization scheme is an onsite power generation and transmission process proposed to harness stranded[4] natural gas energy to provide electric power for onsite use or transmitted by cable to load centres (consumers) or via the nearest existing electric grid. Realization of the constraints and uncertainties in GTW exploitation of stranded natural gas resources requires a techno-economic understanding of how the following operations are linked and affect each other as a process: oil and gas production operations, GTW power plant technologies and electricity transmission technologies.

This chapter describe and discuss the various important elements necessary for the understanding of the proposed GTW concept evaluation. The summary of parameters that would influence the techno-economic of GTs utilization of APG is highlighted. These will be used in the subsequent chapters of this thesis for building models for GTW analysis, finding results, alternatives and impact of changes of the various components of GTW scheme and optimization of the varying parameters as identified to achieve the best APG GT unitization of different scenarios.

[4] Stranded gas as used in this thesis covers both associated and non-associated gas reserves unless otherwise stated. Again, scf (standard cubic feet) represents 1f^3 at ISO pressure and temperature of 101.325 kPa and 288.15 K respectively.

2.2 GTW Technical Description

Primarily the GTW monetization system can be linked to four major units: the gas reserve, gas processing unit, power generation unit and finally the transmission unit. In terms of matching GTW power plant capacity with gas reserves/productions, the interaction between these units plays an interdependent role, forming an important component for evaluating the overall cost of GTW system. Various subset of these units also play a key role in GTW system overall cost estimation and risk assessment to include: gas production decline; distance and terrain for the transmission of power; quality and constituents of the gas; price of electric power; physical location and operating conditions of well among others. Figure 2-2 below represents the schematic diagram of GTW monetization system.

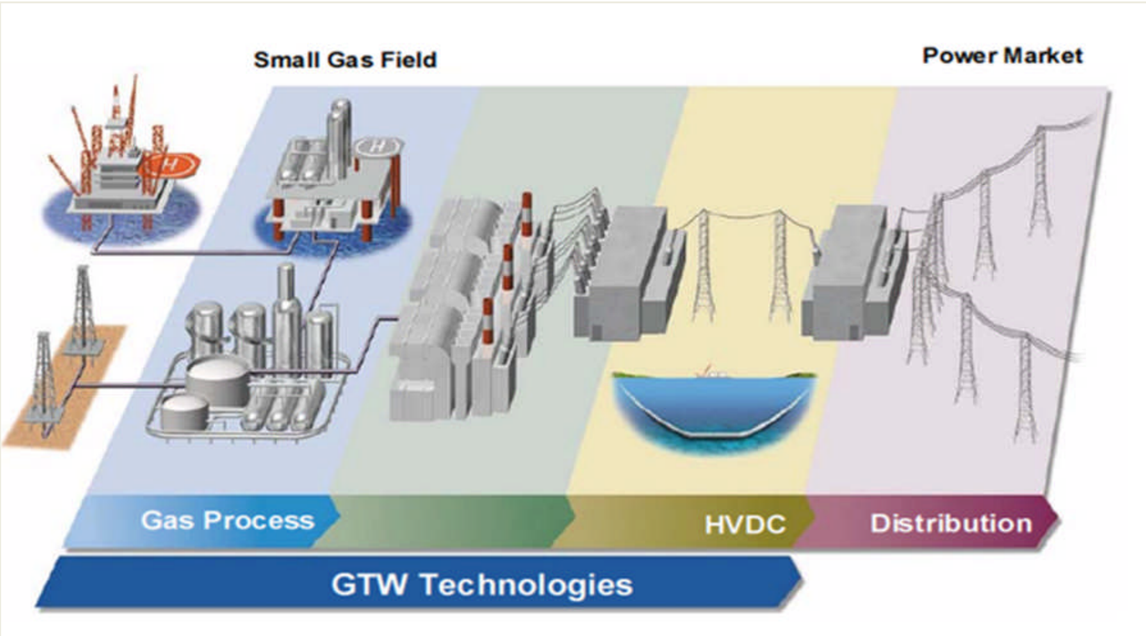


Figure 2-1: GTW Technologies Components Arrangement [9]

2.2.1 GTW Exploitation Algorithm

The analytical scheme representing the GTW monetization system with emphasis on those factors that called for evaluation is shown in Figure 2-2 below. The scheme illustrates the interdependent between subset factors and the major components, and the various ways they can vary to change the economics and technology of the entire GTW monetization system. These variations in subset factors amount to uncertainty in the utilization of APG using gas turbines. The GTW-Combined Techno-economic and Risk Assessment (GTW-CTRA) framework as used in this research is shown as a function of these subset factors like the decline rate; power generation options and capacity; and power transmission options.

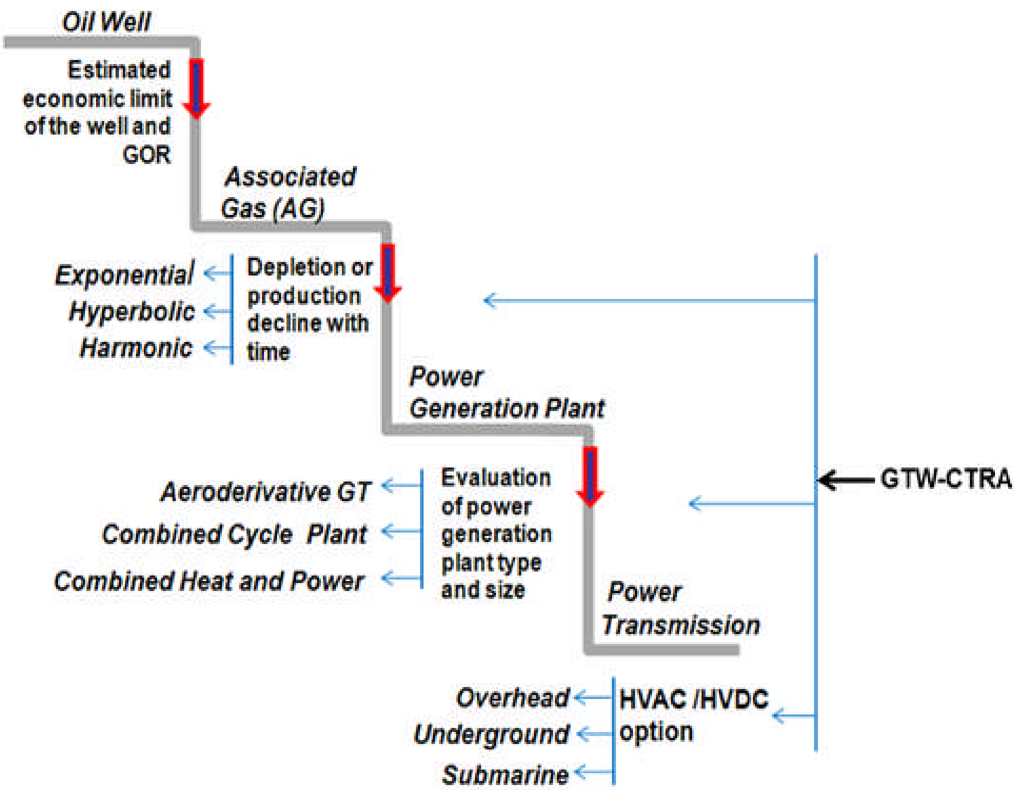


Figure 2-2: APG Monetization GTW-CTRA Framework

2.2.2 Natural Gas Reserves Monetization Technologies

Technologies for exploitation of stranded natural gas are increasing, due to the increasing role of natural gas in global energy mix. Medium-to-small-scale fields have been estimated to be about 80% of undeveloped natural gas fields in the word, with about one-half of it suggested to be stranded gas [4]. However, utilisation of stranded natural gas to augment energy mix demands matching appropriate monetization (commercialization) technology with appropriate reserve size and market requirement. Stranded natural gas monetization technologies can be developed along three main lines as a function of:

- The quantity of the stranded natural gas reserves,
- Distance of stranded natural gas reserves to market, and
- Production site/field and local market specific needs.

Currently the different monetization technology choices for exploitation of stranded (associated and non-associated) gas other than pipeline natural gas (PNG) include:

» Liquefied natural gas(LNG),
» Compressed natural gas (CNG),
» Gas-to-wire (GTW),
» Gas-to-liquid (GTL), and
» Gas-to-solid (GTS) or natural gas hydrates (NGH),
» Gas-to-commodity (GTC) or Gas-to-products (GTP).

While this research is based on GTW monetisation, an overview of current technologies employed in other monetization technologies as listed above are given in Appendix A. The maturity of these gas exploitation modes is highlighted in Table 2-1 below.

Table 2-1: Stages of Present Gas Transportation Modes [28]

Mature	Developing	Future
Pipeline	GTL	NGH
LNG	CNG	
Gas to products	GTW	

2.3 GTW Monetization Reserves Expectation

Several literatures [3; 4; 29], have hinted that GTW monetization scheme will favours medium-to-low volumes stranded gas reserves and medium-to-short distance market scenarios. Certain gas reserves volumes between 10 Bcf to 1 Tcf have been suggested as appropriate reserve volume for GTW monetization, forming the basis for GTW exploitation researches [9; 28].

Whereas other monetisation options like the LNG and CNG require a large gas resource throughput. This often comes from interconnection of APG supply networks from different fields. Such centralised monetization system of APG from different oil production fields requires gathering infrastructure which will eventually increase the overall capital cost of monetization. Perhaps, monetization of isolated medium-to-small throughput APG reserves would rather require a distributed monetization technology. Primary concerns for the distributed monetization options like GTL includes costs, cost inflation and energy inefficiency associated with this conversion [30]. Despite the monetization process adopted, power generation is essential and common to all monetization options.

A list comparing natural gas exploitation options, compiled by Rajnauth et al. [28] highlighted range of gas reserves estimated to be necessary for various exploitation options as depicted in Table 2-2 below. Technically there is no specific guideline for selecting monetization options based on estimated reserves or production history. However, knowing the rate of production in addition to reserves estimated ultimate recovery (EUR) over period of time among other factors would count in determining monetization technology choice.

Table 2-2: Reserves Required for Gas Transportation Projects [28]

Transportation Mode	Amount of Gas needed for Project
PNG	Depends on distance
LNG	>1–3 Tcf
GTW	10 Bcf–1 Tcf
GTL	> 500 Bcf
NGH	> 400 Bcf
CNG	> 300 Bcf
GTC	< 1 Tcf

2.3.1 APG Profile as Oil Production Decline

Estimation of recoverable oil reserves has a practical application and will reveal the particular pressure for abandonment when the reservoir will no longer be economical [31]. However, this translates to oil production and could be quite different for APG production case. Predicting the APG production profile during oil production is important for APG monetization scheme, especially for small-scale standalone APG reserves exploitation.

Reservoir/well production histories revealed that rate of oil and gas production depletes as a function of time. While is difficult to extract all the resources within a reservoir, higher mobility of gas earns it more recoverable percentage of about 80% compared to around 40% of oil, and is subject to different decline profile [32]. Applying the principles of conservation of mass and energy at steady state to a reservoir system [18], suggested that:

(i) Oil production decline could lead to gas production increase, or
(ii) Oil production decline could result in exactly gas decline, or
(iii) Oil production decline could be different from gas decline, or
(iv) Oil production declines while gas production remains constant.

The options leading to serious concern from the above list are (ii) and (iii), since they both will result to variations in fuel schedule during monetization. Difficulties associated with decline increase the uncertainties in estimating the possible recoverable gas volume. This is even more, especially when the nature of decline is not fully known and for a new oilfield monetization scheme development.

Historically, production decline curve analysis (DCA) is use to analyse production data of a producing reservoir to model the production history of that reservoir to predict its future production profile and performance [33-40]. The DCA model concept is based on the assumption that the performance history in the production can be characterised mathematically and remains unchanged in the future. The earliest version of decline curve analysis can be traced back to empirical Arps' equations [33]. Arps historically collected the reservoir decline rates into three basic equations modelling the relationship between production rate and time. While traditional decline history may have gained attention, there are few production and operating conditions decline history assumes to be constant, which actually natural decline trend account for that influence the performance of a well; like the reservoir drive mechanism, rock and fluid properties, well completion, and production practices [41]. Performance of a reservoir is attributed by composite history of various physical parameters describing its current and past actions [42]. Typically, there are three types of production decline curves [33; 34] via exponential, hyperbolic and harmonic decline curves.

The generalised form of decline curve is described by equation ***(2-1)*** below.

$$\mathrm{d} - \mathrm{d}_i \left(\frac{\mathrm{q}}{\mathrm{q}_i}\right)^n \tag{2-1}$$

Production as a function of time (T) for exponential, harmonic and hyperbolic decline is given in equations (2-2), (2-3) and (2-4) below respectively.

$$\mathrm{q}_{(\mathrm{T})} = q_i \exp(-\mathrm{d}_i T) \tag{2-2}$$

$$\mathrm{q}_{(\mathrm{T})} = q_i\,/(1 + \mathrm{d}_i T) \tag{2-3}$$

$$\mathrm{q}_{(\mathrm{T})} = q_i/(1 + n\mathrm{d}_i T) \tag{2-4}$$

Where the parameters are represented as: d— instantaneous decline, rate at time, d_i—initial decline rate, $\mathrm{q}_{(\mathrm{T})}$—instantaneous flow rate, q_i—initial flow rate at the start of decline, and n—empirical constant. When n = 0 the decline curve represents an exponential decline, n = 1 is harmonic decline and n = 2 for hyperbolic decline.

Perhaps in practice, there are conditions such that reservoir producing history cannot be sharply defined by a single production mechanism [42]. Basically decline curve analysis models a production history using equation of a line.

Table 2-3 shown below summaries five methods for using the equation of a line to forecast production.

Table 2-3: Using Equation of a Line for Forecasting Production [43]

Name	Log Rate-Time Shape	Model	Decline
Exponential	Straight		Stepwise

Exponential	Straight	Arps	Continuous straight
Hyperbolic	Curved but converging	Arps	Continuous curve
Harmonic	Curved but limit	Arps	Continuous curve which nearly converges
Amended	Curved but not converging		Dual – Infinite acting amended to a limiting curve

2.3.2 Typical APG Monetization Project Disruption

Normally a conventional APG recovery and monetization facility is constructed and built to a given capacity following the initial APG streams. However, down the line during monetization, APG productions do see a decrease owing to oil production reduction. For an on-site monetization facility supplied from a single oil field, the APG facility operation is tied to resource streams as oil is produced. Around the world, with time traditional standalone APG monetization facilities may experience shutdowns while oil production is still possible. This is envisaged following continuous low supplies of APG from oilfield far below the monetization plant capacity requirements after few years of commencing monetization. Depending on the type of monetization technology being considered, and if such resource decline was analysed during project evaluation stage; otherwise this can bring the overall monetization project to run on the region of unacceptable capacity factor[5].

Materials describing any concept on how to deal with monetization facility during decline were not found in literature. Part of the work in this research will examine the way GTW monetization could be managed as APG production depletes. With the current monetization technologies trend tending towards mobile standalone unit, believed to have flexibility enabling them to be reused

[5] Capacity factor or capacity utilization factor is the ratio of an average actual plant use to the maximum plant built capacity.

for another projects. It is of great importance to evaluate the impact of decline on monetization economics.

The Kaji-Semoga oil field located about 80km from Palembang South Sumatera province of Indonesia has an on-site LPG facility that recovers and monetize the flared APG. Its estimated APG production in 2004 was 15,800mscfd which declines having a daily production estimated to be 3,000 mscfd in 2014. This means this plant will be shut down following the APG depletion which is far below its designed facility capacity [13]. Another one like it but more challenging is the UK's Magus oil field [12] located in the Northern North Sea160km north-east of the Shetland Islands. The APG from this field were initially transported via pipeline and later APG production decline resulted in switching monetization plan to power generation. It was not long when studies on the same field revealed that using APG for EOR will increasing the oil production up to 30 to 40%, whereas the amount of AGP required to achieve the EOR project is more than APG the field is producing. Next APG from Foinaven and Schiehallion fields initially being injected into gas disposal well then were sorted for the purpose of makeup-gas for EOR project. This leads to new pipeline construction to connect this field to the Magnus platform to ensure the declined APG production is able to meet the required gas for the EOR projects and power generation. The ups and downs associated with such monetization are capital intensive and could have been better managed if the decline was foreseen and accounted for in the initial monetization project plan.

Other practical concern raised is the interaction of the GTW plant with the oil production facility. In the event of the power plant shutdowns for any reason, the oil production facility will be shutdown likewise or the gas released recurred to flare [19; 44; 45]. Also the ability of both oil production facility and GTW plant to respond within specific safe time in the event of any emergency and after shutdown period to come up online immediately was questioned as prolonged shutdown will incur undue financial expense.

2.4 Choice of GTW Monetization Power Plant

The selection of power plant cycles for GTW monetization of APG will depend on several factors. Thermodynamically, natural gas-fired power plant can run on either Rankin cycle (steam turbine) or Brayton cycle (gas turbine) or on both cycles together (combined-cycle) system. Thermodynamic of simple cycle gas turbine could be modified to improve desired performances by incorporating other components (heat-exchange or regenerative cycle), leading to: recuperated cycle, intercooled cycle; and intercooled and recuperated cycle. These power plants are employed for different load cycle requirements such as base load, peak looping unit, mid merit unit, as well for standby generator applications. For instance, variation in customer's power requirement cannot be accounted for with base load unit alone. Therefore, a more flexible unit is required to meet daily peak, this unit is called the intermediate power unit. They have lower capital cost than the base load unit but with lower efficiencies. They account for 30-50% of maximum hourly power requirement and 20-30% of annual load requirement of a typical facility. Another unit called peak unit is used to provide peak load requirement only. The peak could be in the order of hours, months and year. Peak units are capable of achieving full load within five minutes from cold condition with power up to 150 MW. They generally supply up to 5% of the total available energy of the system during their operation.

Whereas thermal efficiency and power output are the primary considerations in power plant thermodynamic cycles analysis [46]; in addition, GTW power plant will be concerned with the gas quality [9]. Fuel supply schedule uncertainties resulting from APG production dynamics, and considerations of logistics of makeup-fuel option also requires evaluation. The basic power plant considerations for GTW monetization of APG is likely to be largely dependent on specific site conditions to include constraints from oil production practices, environmental concerns, transmission distance and nature of local power requirement profile. The viability of the preferred cycle will not only be appropriate for the initial reserve size being considered but will also account for flexibility required during reserve depletion and compatible with oil production operations with a minimal disruption to oil production planes.

Capacity to load distance which simply describe reserve size, and distance of generating plant to the load centre or transmission distance have been dominant factor in the economic analysis of gas monetization [1; 9; 25; 47]. The impact of decline on APG monetization has not received attention, despite the fact that this can bring a huge change in monetization economics whether makeup-fuel (dual-fuel) is being considered or not. Because price of oil is different from gas price and the amount of oil used for makeup-fuel will increase as gas decline, requires production decline to be considered a major factor during GTW monetization of APG.

2.4.1 Gas-Fired Power Plant

The most reported type of power plant for GTW monetization is the natural gas combined cycle (NGCC) power plant [9; 48; 49] Figure 2-3 below. The NGCC power plant is favoured because of its increased thermal efficiency.

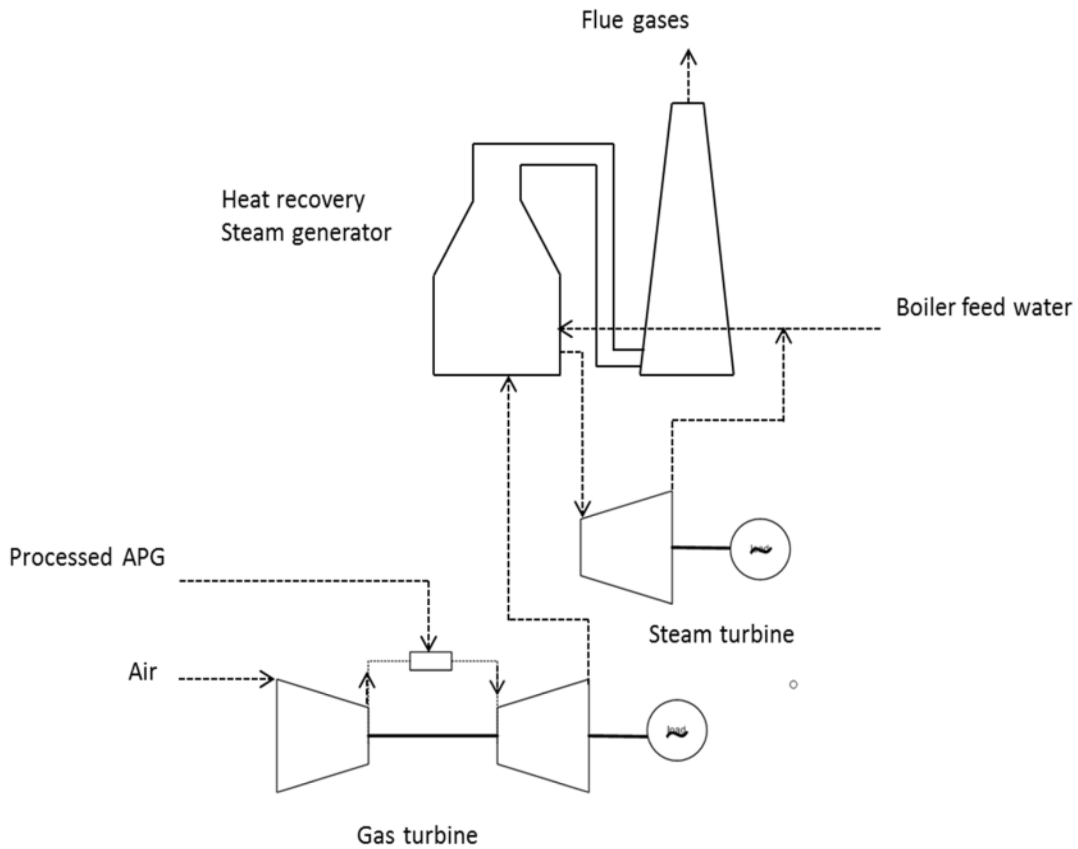


Figure 2-3: Combine-cycle Power Plant

In some cases depending on load requirements, economics, among other factors, can lead to development of existing simple cycle power plant into a combined cycle, or co-generation, or steam for heat and cooling called tri-generation. A typical combined application of GT engine in GTW monetization of APG will include: combine generation of steam for thermal enhance oil recovery (EOR) i.e. steam Enhanced Oil Recovery (S-EOR) and revolutionized carbon capture for EOR. The EOR project would require evaluation of the quality and quantity of rejected heat and flue gases from the GT engine to produce the required steam condition and profiles to match the S-EOR projects. For the CO_2 as employed in EOR projects Figure 2-4 below, economics and energy used for carbon capture will be among the import factors that will drive the economic viability of such projects.

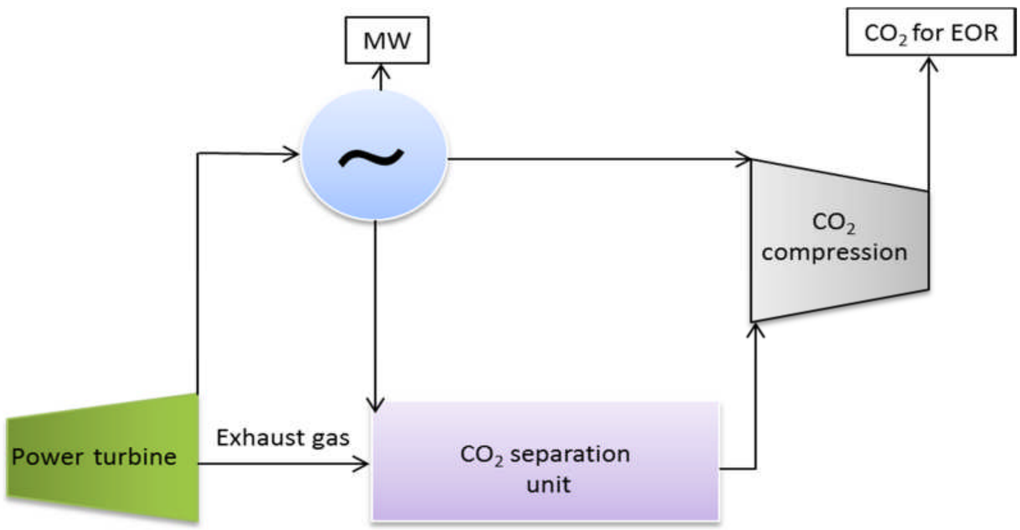
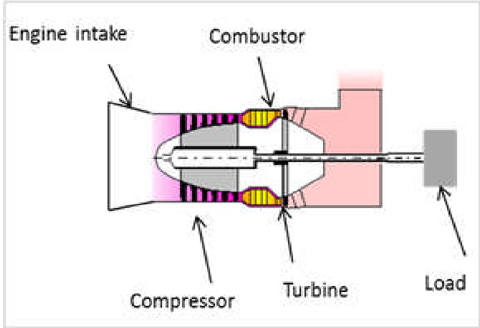
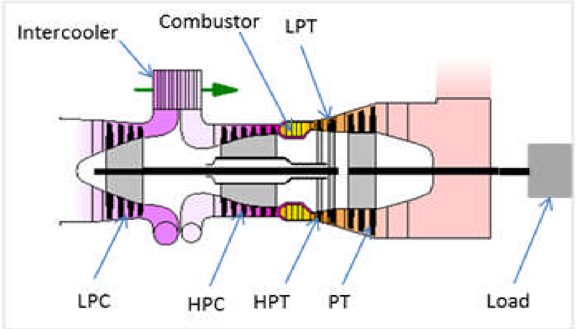


Figure 2-4: CO_2 for EOR Project

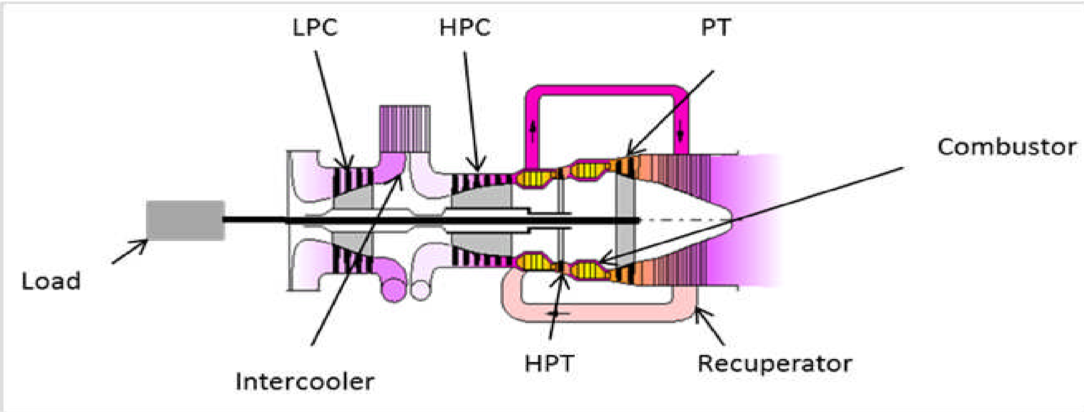
The ability of the simple cycle power plant to be converted or upgraded to various cycles to satisfy different energy requirements makes it a fundamental and interesting cycle for this research. This is one of the attributes that allowed the CT to be the basis for the GTW power plant as used in this study. GT engines used for this study are classified into two categories: heavyweight and aero-derivative engines. A typical monetization power plant model in this research comprises of mix of different engine sizes and type. Here the smaller engine units below 100 MW come from aero-derivative engines and bigger engine units above 100 MW are heavyweight GT engines. Different GT engines cycle configurations as considered in this study are shown in Figure 2-5 below.



(a) Single spool Engine



(b) Intercooled Engine



(c) Intercooled Recuperated Engine

Figure 2-5: GT Engine Configurations [94]

2.4.2 Engine Component Degradation

The erratic nature of AGP during oil production can lead to a prediction that a make-up fuel could be require at some point during GTW monetization of APG. The makeup-fuel option will be possible because of the ability of industrial GT engine to run on dual fuel and burn most heavy oil. This could be arguably an advantage during GTW monetization of APG. However the composition of most bunker oil suggested as a make-up fuel [9] could entail a different combustion approach would be adopted as the only way such fuels could be utilized owing to their obscure corrosive and erosive nature.

Normally a direct firing where fuel is pumped into the combustion chamber is used for normal fuels like natural gas, kerosene, diesel and other less common fuels [50]. On the other hand indirect firing is where fuel is burnt external to the GT and the heat is transferred using heat exchanger to the compressor delivery air. The consequences of indirect firing include lowered output power and thermal efficiency due to reduction in both mass flow and specific heat capacity at constant pressure (CP) in the turbines.

Deviation of most APG and bunker oil quality from typical pipeline gas quality would not only result in low thermodynamic performance of the GT engine [51] but will initiate deterioration of the hot path of the GT engine from gas contaminant and gas composition [52], often requiring a special GT combustion system. Other major and direct issues would come from operational view point. Where decreased service life is expected from effect of degradation and cost of maintenance will increase due to short time between overhauls.

While most APG composition in some part of the world are of greater quality close pipeline gas quality, another factor that could lead to GT components degradation is the environmental factor. This is true considering the amount oil well located offshore. GTs in offshore GTW site would be affected by airborne sea salt contaminants. GT ingestion of the sea salt is susceptible to fouling, erosion and corrosion of the gas hot path mainly due to dual nature of the salt. Generally the degradation of GTW GTs application can be combination of fuel quality and environmental factors associated with site location.

2.4.3 Effect of Fuel Chemical Composition

APG is a high-calorific fuel with chemical compositions which varies from region to region. Generally variations in composition of gas can have effect on its heat content and stability as a fuel for GTs. For instance, high mass composition of nitrogen can reduce the calorific or heating value of the gas [53]. Hydrogen content of the fuel affects the flame speed, which is capable of distorting the uniformity of heat released in the combustor [54]. The major economic factor highlighted by [55-57] was fuel and its effect on GT performance. When the turbine fuel is changed from natural gas to liquid fuels as in in case of (makeup-fuel) for engine running on dual fuel systems [55] is noticeable and is in the neighbourhood of:

(i)	+4 to +6	for engine power output,
(ii)	0.5 to +1.5%	for engine rotational speed,
(iii)	+2 to +3%	for engine inlet mass flow,
(iv)	+2 to +3%	for HPC delivery pressure,
(v)	+3 to +4	for fuel energy flow and
(vi)	-1 to -2%	for specific fuel consumption.

The GTs running on dual-fuel (makeup-fuel option) system requires modification of components: fuel injectors and combustors due to high fuel flow required to achieve similar power rating for low calorific value (LCV) fuels [58; 59]. The ability of the GTs to run on hydrogen rich fuels are being considered by different GTs manufactures like GE [60; 61], Siemens [62; 63], Alstom [64] and Mitsubishi heavy industries [65].

The Wobbe Index (WI) can be used to characterise the variation in fuel composition. The key hardware used to adapt the changes introduced by fuel composition variation is the control system. It has the ability to measure and adjust quantity necessary for the operability boundaries of the GTs affected by fuel quality to include combustion dynamics, emissions and blowout [66]. A control systems studied for this purpose has been reported [67; 68]. They employed physics-based models of GTs operability boundaries like combustion dynamics, emissions, etc. in real-time to estimate the level of these boundaries; their field test was validated using a 7FA+e GT engine with a DLN2.6 combustor operating in 107FA combined-cycle mode using heated fuel.

Despite different species of APG, the interest of this variation in composition from operation and performance point of view can be categorically summarised into:

» Change in plant emissions,
» Change in generated power output, and
» Degree of GT component degradation.

A composition of a typical Nigerian APG from Kwale oil field [49] is shown in Table 2-4 below as reported from Nigerian Agip Oil Company (NOAC). Range for most composition of the Russian APG as reported [69] in molar basis is being compared in Table 2-5 below against the typical natural gas blend use for deriving gas properties in most GT thermodynamic cycle studies [50].

Table 2-4: Molar Composition of the APG – NAOC Chemical Lab., 2001

COMPONENT	Vol. %
Water	0.26
Nitrogen	0.61
Carbon Dioxide	2.59
Hydrogen Sulphide	0.001
Methane	78.81
Ethane	10.46
Propane	4.62
Iso-butane	0.79
N-Butane	0.97
Iso-pentane	0.31
N-Pentane	0.27
N-Hexane	0.21
N-Heptane	0.10

Table 2-5: Typical Composition of Natural Gas and APG

Typical Common Blend of Natural Gas (%)	Composition		Typical APG (%)
95	Methane		50-70
1.9	Ethane		5-10
1.5	Nitrogen		1-10
0.2	Carbon dioxide		1-10
0.5	propane	LPG	5-15
0.5	I-Butane		
0.1	N-Butane		
0.1	I-Pentane		
0.1	N-Pentane		
0.1	Hexane		

2.5 GTW Monetization Emissions

The environmental impact from GTW monetization emissions for scenarios when makeup-fuel is the bulk source of fuel during gas decline would be different when compared to running APG alone and requires evaluation. Mainly the major GTs pollutants are carbon and nitrogen based oxides including unburned hydrocarbon (UHC) and smoke. Emission from gas flaring is dominated by carbon dioxide, heat, smoke and UHC with the last two pollutants resulting from incomplete combustion. On the other hand, gas venting to the atmosphere constitutes greenhouse gases predominantly CH_4 which has high GWP. Other pollutants like oxides of sulfur (SOx) are bound to be present depending on the composition of the APG source and makeup-fuel (heavy oils) used. The most common of SOx is SO_2 [70]. The overall life cycle emission from APG monetization compared to emission from flaring and/or venting will represent a significant parameter. Health and environmental hazards associated with most emissions from fuel combustion are outlined in Table 2-6 below.

Table 2-6: By-Product of Combustion [71]

By-product	Source	Effect
CO	From incomplete combustion	A toxic exhaust gas, continuously monitored
C_nH_m	Also called unburned hydrocarbon (UHC)	Strong-smelling, potentially carcinogenic substances
VOC	Without methane and ethane, the UHC is called volatile organic compounds (VOC)	VOC contributes to formation of ground-level atmospheric zone
Smoke	Soot particles	From incomplete complete combustion; assist in the formation of carcinogenic substances
NOx	NO and NO_2 generated from air at very high temperature	Negative effects on plants; part of infamous acid rain (HNO_3) and destroys the ozone layer of the earth
SOx	SO and SO_2 , unavoidable oxidation products when the fuel contains sulphur	Major components of acid rain (H_2SO_3 and H_2SO_4)
PM	Particulate matter	Soot and other particulates from incomplete combustion
PM 10	Particulate matter smaller than 10 microns	Natural gas combustion produces a very small amount
PM 2.5	Particulate matter smaller than 10 microns	Found mostly in liquid fuel combustion

2.5.1 GTW Power Plant Carbon and Nitrogen Oxides

The amount of carbon oxides and NOx emission from GT engines employed for GTW monetization may be linked to engine operations, performance and fuel quality. At some point in the GTW monetization when gas decline entails running GTs on part-load and/or using different fuel from APG, emission will be estimated to ensure is maintained within the acceptable limit both environmentally and economically. The major pollutants emitted by GTs are shown in Table 2-7 below.

Table 2-7: Principal Pollutants Emitted by GTs [72]

Pollutant	Effect
Carbon monoxide (CO)	Toxic
Unburned hydrocarbons (UHC)	Toxic
Particulate matter (C)	Visible
Oxides of nitrogen (NOx)	Toxic, precursor of chemical smog, depletion of ozone in stratosphere
Oxides of sulfur (SOx)	Toxic

Reducing NOx pollutant is the main motivation for GTs combustor development programmes [73]. The chemical mechanisms representing the pathway for NOx formation is given in equations (2-5) to (2-11) below [73], the HCN to NO reaction in equation (2-11) is just initiation process. More detailed information on the chemical pathway and full description of the prompt reaction is reported in [74; 75]. Mainly the combustion temperature (or turbine entering temperature, TET) is the parameter affecting NOx formation. The coexistence of NOx, CO and UHC in manner as illustrated in Figure 2-6 and Figure 2-7 below posse concern to NOx reduction. The problem of NOx formation can be solved by lowering TET or operating away from stoichiometric, unfortunately this will give rise to a condition that favours both CO and UHC formations and perhaps low cycle efficiency. Similarly, increasing TET will reduce CO, UHC, and improve cycle efficiency but will work in favour of NOx formation. Currently methods for GTs emission reduction include water injection, selective catalytic reduction (SCR), and dry low NOx systems.

Emissions are not easy to calculate due to the fact that their chemical kinetics are not fully mapped by equilibrium based analysis. Method used in estimating emissions include computational dynamics (CFD) approach, physics based approach and empirical and semi-empirical approach [76-80].

Extended Zeldovich mechanism:

$$\mathrm{O} + N_2 \leftrightarrow NO + N \quad (2\text{-}5)$$

$$\mathrm{N} + O_2 \leftrightarrow NO + O \quad (2\text{-}6)$$

$$\mathrm{N} + OH \leftrightarrow NO + H \quad (2\text{-}7)$$

Nitrous oxide:

$$N_2 + \mathrm{O} + M \leftrightarrow N_2O + M \quad (2\text{-}8)$$

$$N_2O + O \leftrightarrow NO + NO \quad (2\text{-}9)$$

$$N_2\mathrm{O} + \mathrm{H} \leftrightarrow NO + NH \quad (2\text{-}10)$$

Prompt:

$$N_2 + \mathrm{CH} \leftrightarrow HCN + N \quad (2\text{-}11)$$

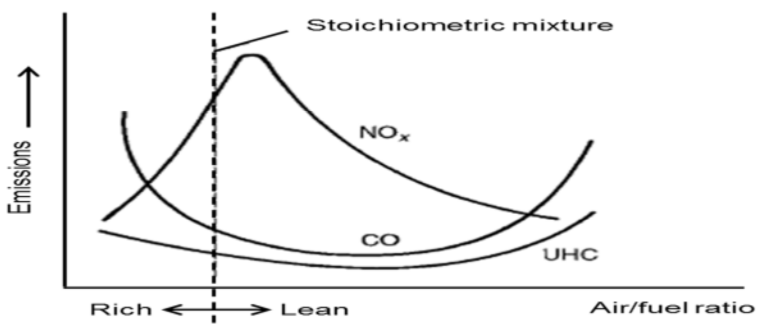


Figure 2-6: Dependance of Emission on Air/Fuel Ratio [70]

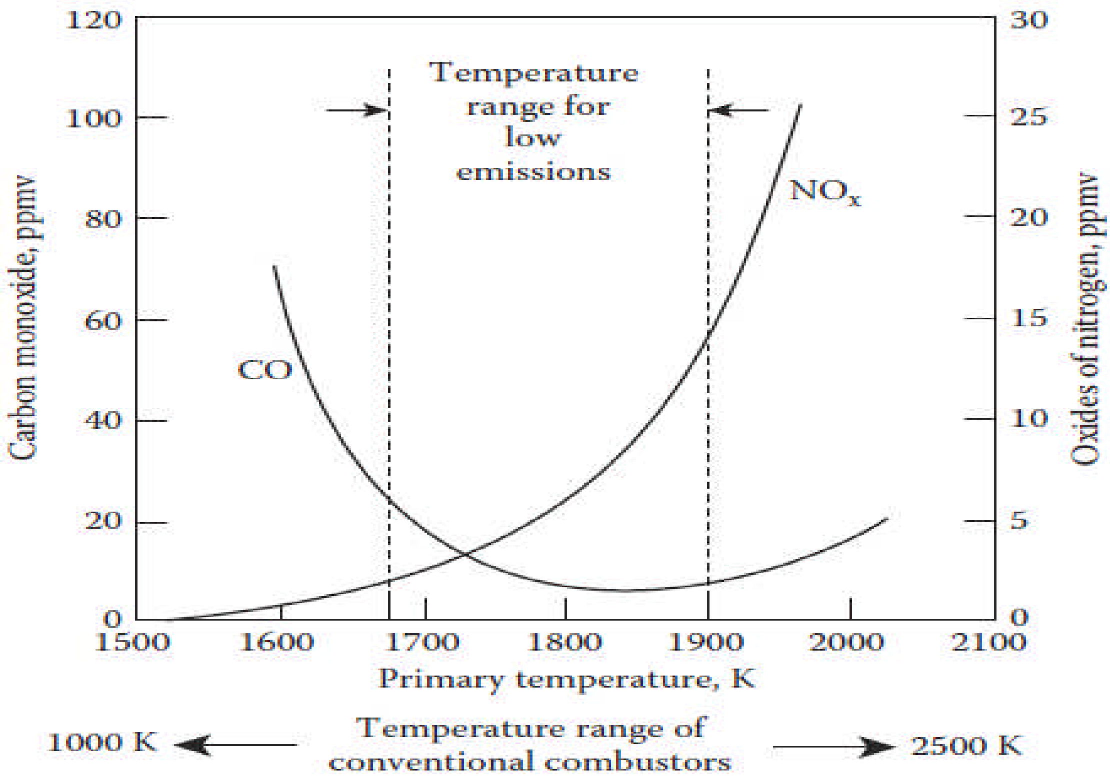


Figure 2-7: Influence of Temperature on CO and NOx Emissions [72; 81]

2.5.2 Economic of Gas-Fired Power Plant

Generally economics of gas-fired power plant is thermodynamic linked with the performance of the plant (turbine cycle) [20]. For instance, in a combined cycle power plant a decrease in gas turbine exhaust gas temperature (EGT) will result in a reduction in steam pressure for the steam cycle. Simply put, in a combined cycle plant selecting high compressor pressure ratio to improve turbine efficiency could lead to a drop in steam cycle efficiency and definitely reduction in overall thermal efficiency of the combined cycle plant.

While thermal efficiency is important for power plant, is not the only criterion from economic point of view used for power plant selection. Instead unit cost of electricity sent out—a combination of thermal efficiency and capital cost of plant is always considered. Capital cost itself is function of different factor and can vary from one location to another due to cost of logistics. Typical power plant costs are capital and production cost. In general capital costs are used to assess if power utility project are able to obtain financing in order to be able to pay for the fixed charges associated with these costs. Capital cost can be expressed in total say in dollars or as a unit capital costs in dollars per kilowatt net power output. Likewise production costs are the true indication of the cost of power produced. They can be calculated annually or in dollars per kilowatt hour ($/kWh). Production costs consist of: A fixed charge for the capital costs, costs of fuel and operational and maintenance costs all in $/kWh.

Simply put,

$$\text{Production costs} = \frac{\text{total (FC + fuel cost + OM)\$ spent per period} \times 10^3}{\text{KWh (net)generated during same period}} \quad \text{2-12}$$

Where FC = fixed charge costs, and OM = operation and maintenance costs, $/yr

$$\text{Plant operating factor, POF} = \frac{\text{total net enregy generated by plant during a period of time}}{\text{rated net eneergy capacity during same period}} \quad \text{2-13}$$

Normally the period and POF are taken to be one year and 0.8 respectively; therefore annual operating cost based on these assumptions could be equally rewritten as:

$$\text{Production costs} = \frac{\text{total (FC + fuel cost + OM)\$} \times 10^3}{7000\ \text{P}}\ \text{mill}/\text{kWh} \quad \text{2-14}$$

Where P = electric plant power rating in kW. Plant operating factor, POF of 0.8 means that the plant is 80% available at its rated capacity throughout the period—that is one year in equation 2-6 above. Converting to hours year implies 0.8(365×24) = 7008 ≈ 7000 h/yr.

2.6 Gas Processing

Raw natural gas from well contains hydrocarbon, carbon dioxide, hydrogen sulfide, water, mercaptans and other impurities; requiring some degree of processing to achieved a desired gas quality. The most concern for gas is the free sulfur and sulfur compound especially H_2S. Sulfur oxidizes during combustion forming SO_2 and then acids which are very corrosive. On the other hand, the suggested makeup-fuel —the residual crude oils in addition to these contaminants contain large quantities of metallic compounds that oxidize to form ash. The problem with this ash is that it contains various non-volatile inorganic compounds. These compounds at about 925 K tends to be sticky and foul the nozzle guide van and turbine blades, when ash content is more than 0.1% the trend can be more serious [72].

The processing of oil/and or gas include water treatment for safe and economical storage/transportation from the production facility to the point of custody is called field handling or processing [82]. Generally, the scope or extent to which a raw gas or fuel is processed would depend on the processing objective (i.e. difference between the fuel and the required GT fuel quality), gas source/type, and the location and size of the fields [83].

2.6.1 APG Processing Specification

Associated gas for gas turbine utilization cost estimation would typically start from quantity and quality of the gas in the reserve being considered; this will have a significant cost implication in the overall conversion scheme from processing and performance point of view. Generally gaseous fuels present no special problems to industrial GTs [72] as such field or wellhead processing is probably sufficient. This is far less than gas processing where gas is processed for different reasons including production of gas sales specific quality [45; 84;

85] Figure 2-8 below and processing for separation of natural gas liquids6 (NGLs) Figure 2-9 below for different feedstock [86] depending on the majority of the gas composition.

Table 2-8: NGL Products and Markets

NGL Components	**Market Use**
Ethane (C_2)	Petrochemical feedstock for manufacture of ethylene
Propane (C_3)*	Petrochemical feedstock for manufacture of propylene and ethylene Residential and commercial fuel in rural areas, transportation fuel, and cooking grills
Iso-butane (*i*-C_4)	Refinery feedstock to alkylation unit, methyl-tertiary-butyl-ether feedstock Fuel use as a component in LPG
Normal butane (*n*-C_4)	Gasoline blending, petrochemical feedstock for manufacture of light olefins Fuel use as a component in LGP, isomerized to *i*-butane
Natural Gasoline(C_5+)**	Refinery feedstock to reform or isomerization unit Petrochemical feedstock for manufacture of light olefins

*Often sold as liquefied petroleum gas (LPG). LPG can be C3, C_3-C_4 mix or predominately C_4.
**Natural gasoline is a North American term, also referred to as light naphtha or condensate in other regions.

[6] Natural gas liquids (NGLs) include ethane, propane, butane, iso-butane and natural gasoline (i.e. pentane plus) [85].

These NGLs serve different purposes and are sold to different customers Table above [87]. The processing of APG for GTW monetization should be fair with a minimal cost, safely and mindful of the environment. This should target only those compositions that would be detrimental to the GT engine health, performance and the environment.

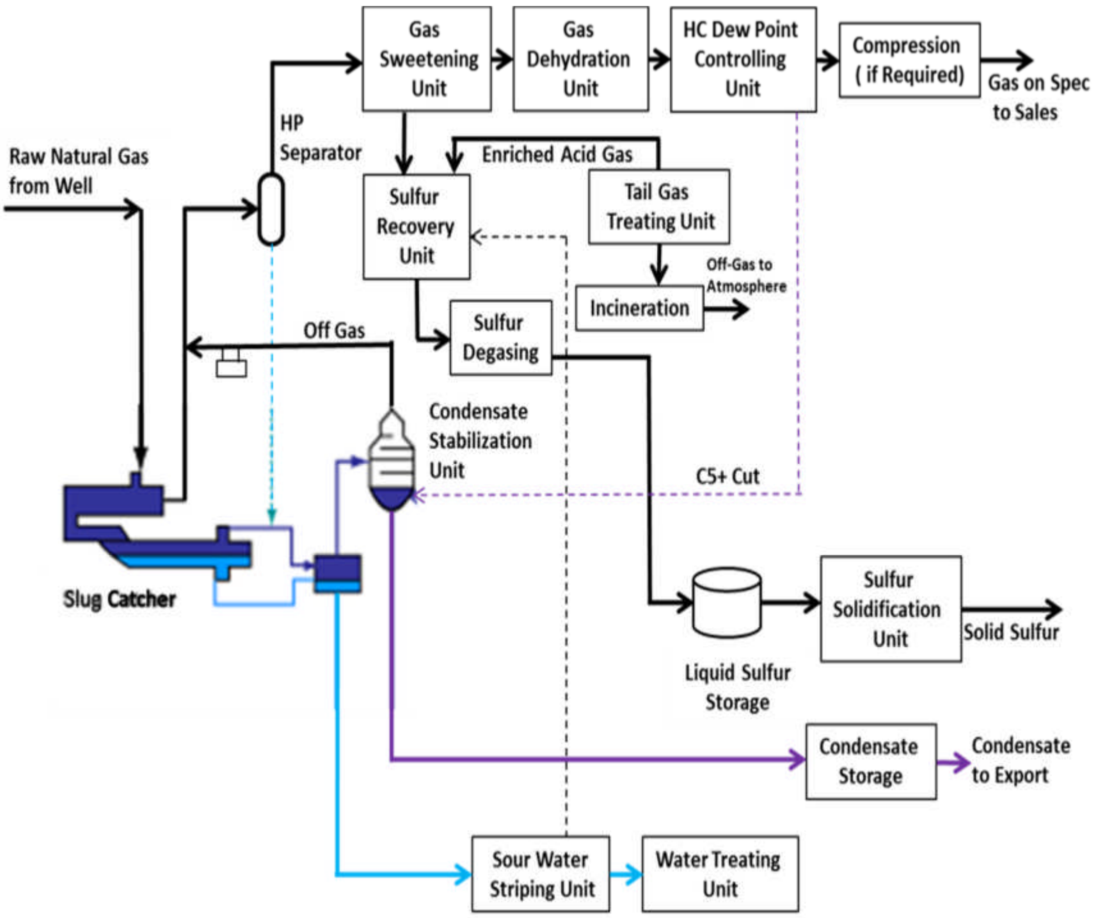


Figure 2-8: Gas Processing Plant Flow Diagram for Producing Sales Gas

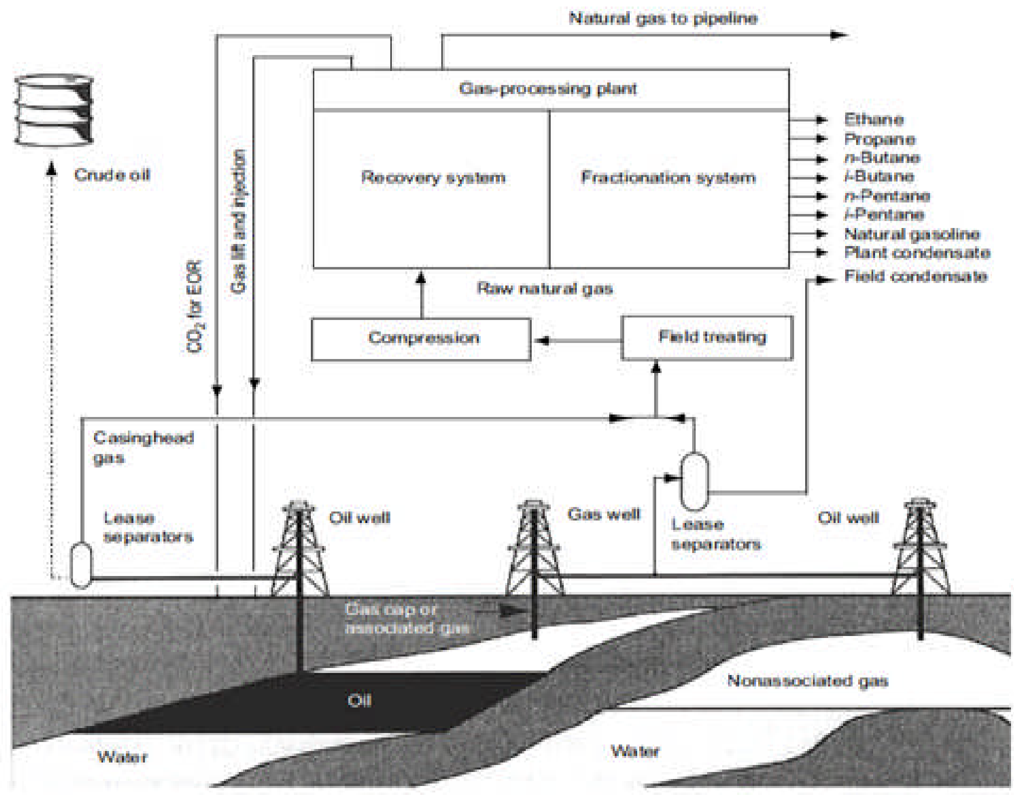


Figure 2-9: Gas Processing and Total Production System

2.7 Electricity Delivery Systems

Delivering the generated electricity is among the top concern for GTW monetization economics. Mainly due to high cost associated with construction of transmission facilities and in most cases long distance exists between the oilfield and existing grid. Electric power delivery systems consist of the transmission facilities which deliver the electricity from the generating station to substation/industry and the distribution systems that delivers the electricity to various home/commercial services. Electricity delivery systems could further be categorised into transmission, subtransmission, primary distribution and secondary distribution, depending on their operating voltage levels which varies among countries. Mainly the power/electricity delivery system that is of primarily considered in GTW scheme is the transmission facility.

2.7.1 Types of Power Transmission

An electric power transmission could be high voltage alternating current (HVAC) or high voltage direct current (HVDC). Either of these could be delivered via overhead or underground systems and submarine cable for offshore scenarios. Terms that are interchangeable or often used to describe transmission lines are the grid, bulk power system and the interconnection [56] The choice of transmission is often influence by such factors like terrain, distance involved, capital cost, maintenance cost and right-of-way (ROW) issues.

There is no exact distinction in voltage levels classification between the subcategories of electric delivery facilities for instance in the US. This was contributed partly due to exclusive dependency use of standardized transmission structures to reduce capital cost involved in designing and testing of a new delivery facility [88] especially the transmission lines. The North American Electric Reliability Corporation (NERC) reliability standard classified 100 kV facilities and above as bulk electricity systems. Table 2-9 below shows common HVAC transmission voltages in United State. However there are standard voltage levels, depicted in Table 2-10 below with those nominal voltages value rating of 345 kV, 500 kV, and 756 kV rated as extrahigh voltages (EHV) in the US, while in Europe 400 kV transmission is mainly used and also classified as EHV, transmission of 1100 kV have been seen in Japan and Russia [89].

Table 2-9: Common HVAC Transmission in the US [89]

Systems	Voltages included
Transmission	765kV, 500kV, 345kV, 230 kV, 169 kV, 138 kV, 115 kV
Subtransmission	169kV, 139 kV, 115kV, 69kV, 34.5 kV, 27kV
Primary distribution	33kV, 27kV, 13.8kV, 4kV
Secondary distribution	120/240 volts, 120/208volts, 277/480volts

The transmission of power from GTW monetization is often not favourable using HVAC due to high losses over long distance and amount of power generated. HVDC is recently receiving more attention over HVAC for long distance transmission lines. Advantages of HVDC transmission systems include technically unlimited distance of transmission, with only losses being the economic limit; provide means of controlling magnitude and direction of power transmitted; requires minimal ROW; carries more power for same conductor size when compared with HVAC. However disadvantages of HVDC are mainly due to high capital cost and inadequate technology to produce reliable and economic circuit breaker [56]. Positive recent development in HVDC research suggests that in future capital cost of GTW monetization would be reduced.

Table 2-10: Standard System Voltages [89]

Rating (kV)			
Nominal	**Maximum**	**Nominal**	**Maximum**
34.45	36.5	230	242
46	48.3	345	362
69	72.5	500	550
115	121	765	800
138	145	1100	1200
161	169		

2.7.2 Economic Estimation of Transmission Facility

Economic estimation of new HVDC technologies for GTW project feasibility study is somewhat difficult because of limited available data and continuous rapid development of this technology. Normally economics of power transmission involves consideration of different components of the transmission structures and accessories. For an overhead transmission lines the typical components are conductor and tower economics. However this defers for underground transmission lines and submarine cable power delivery systems. Analysis of conductor economic is usually done using the present value or worth of revenue required approach equations (*2-15*) to (*2-17*) below. Depending on conductor size, below 340 kV is done on economic merit alone. While conductor size selection of 340 kV and above will consider corona-related electrical environmental effects, radio and audible noise effects in addition to economic consideration [89]. Conductor selection cost concept diagram is presented in Figure 2-10 below. The conductor economic modelling uses the sum of present value levelized annual fixed charges on the whole line capital cost and annual expresses incurred due to lines losses. The cost of line losses is calculated using the amount required to generate the losses.

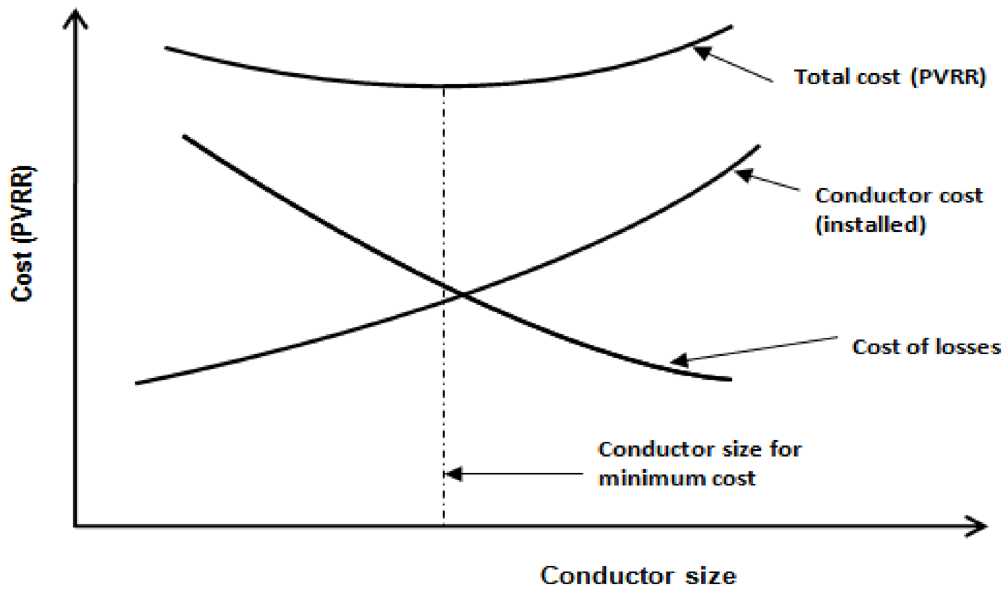


Figure 2-10: **Conductor Economics Concepts [90]**

$$\mathrm{PVRR} = \sum_{n=1}^{N}\left(1+\frac{i}{100}\right)^{-n} \times \left(\mathrm{CI} \times \frac{F_L}{100} + \mathrm{AD_n} + \mathrm{AEC_n}\right) \quad \text{2-15}$$

$$\mathrm{ADC_n} = \frac{C_{kw} \times \mathrm{ESC_n}}{10^3} \times \frac{F_g}{100} \times \left(1+\frac{\mathrm{RES_g}}{100} \times I_L^2 \times \frac{R}{N_c} \times N_{ckt} \times N_p\right) \quad \text{2-16}$$

$$\mathrm{AEC_n} = \frac{C_{MWh} \times \mathrm{ESC_n}}{10^6} \times 8760 \times \frac{L_f}{100} \times I_L^2 \times \frac{R}{N_c} \times N_{ckt} \times N_p \quad \text{2-17}$$

Where *PVRR* is the present value of revenue required; ADC_n annual demand charge for line losses for year n, and AEC_n is the annual energy charges for year n. Other parameters are follows: *N* = evaluation period in years, *n* = the nth year, *i* = annual discount rate in percent, *CI*= total per mile capital investment, F_L

= line fixed-charge rate in percent, ADC_n = per mile demand charge for line losses for year n, AEC_n = per mile energy charge for line losses for year n, C_{kw} = installed generation cost in \$/Kw, ESC_n = escalation cost factor for year n, F_g = generation fixed-charge rate in percent, $RESg$ = required generation reserve in percent, I_L = demand phase current in amperes per circuit, R = single conductor resistance in ohms per mile, N_{ckt} = number of circuits, N_p = number of phase, AEC_n = annual energy charges for year n, C_{MWh} = cost of energy generation in \$/MWh, ESC_n = escalation cost factor for year n, L_f = loss factor for determining energy losses in percent, I_L demand phase current in amperes per circuit, R = single conductor resistance in ohms per mile, N_{ckt} = number of circuits , and N_p = number of phase.

2.8 Summary

Numerous literatures have been considerably examined to further strengthen the basis for this study. This was stretched to cove areas as pertain to natural gas flaring, gas monetisation techniques, associated gas production dynamics, natural gas processing, gas turbine performance criteria and economic analysis of power generation and transmission.

Though, there is increasing interests for associated gas utilization (monetization). Perhaps, different associated gas throughputs will suite different monetisation techniques. There have been a growing number of stranded gas reserves and their utilization options becoming more capital intensive. The GTW has been arguably the most utilization option campaigned for small associated gas throughput but overall specific researches targeted for GTW is relatively small compare to other monetization options. Conclusively GTW despite its high recommendations from different literatures is still in premature stage and there was no literature found that present techno-economic analysis for this option.

Production decline is not favourable, yet associated gas production decline has not been linked with any monetization technology. Compositions of associated gas vary widely but their high content of methane is among factors that makes them attractive fuel for power generation. Therefor a need for GTW evaluation model that will integrate associated gas production profile and power plant options to evaluate associated utilization is necessary. Hence, the current research develop a prediction tool for onsite gas turbines associated gas utilization, modelled to account for uncertainty in associated gas production and capital cost layout lays.

Chapter 3

Techno-Economic Algorithms

3.1 Gas Turbine Associated Gas Utilization Model

The parameters employed in the development of gas turbine utilization of associated petroleum gas (APG) techno-economic model comprises of APG production prediction module, gas turbine for power generation performance module, and economic/ investment module. Standard decline curve equations were used for the gas production prediction module. The power plant module is developed from thermodynamic results of gas turbine engines simulation supplemented with data from literature surveys in line with the objectives of this research. Economic and investment module is developed using revenue requirement and annualized cost methods to generate cost of electricity (CoE).

The development of the entire models (GTW evaluation algorithm) were carried out in such technical constructive manner ensuring all options are considered avoiding deferring any aspect at the end when options might be foreclosed owing to earlier decisions. Therefore, this GTW evaluation algorithm involves technical integration of different modules that forms this framework. However, each of these modules has many components associated with them. Thus, for the integrating framework, a sequential-modular approach is preferred.

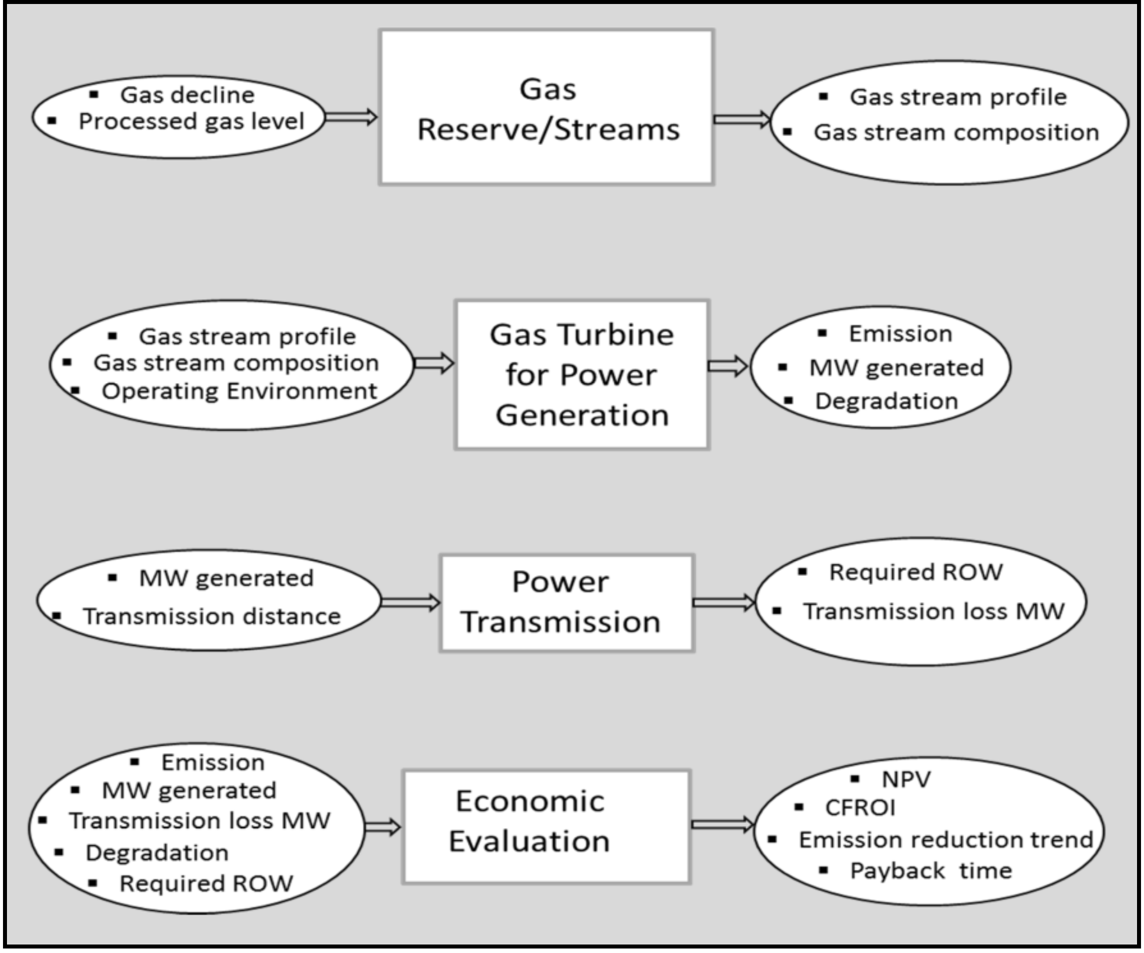
Typically a sequential-modular approach is one of the methods used in developing flow sheeting or process simulation programmes for thermal system analysis or optimization [91]. In general this method allows the engineers to model the behaviour of a system or components under study to carry out thermal analysis of the system, sizing, costing, and optimization as may be required for the concept development. This process entails sequential calling of established models associated with various components particular to a flow sheet by an executive programme using the output stream data for each component as the input for the next component.

Another method for developing flowsheeting or process simulation is the equation-solving approach. Here, equations representing the individual flow sheet components and the links between them are assembled as a set of equation for simultaneous solution.

Block diagrams showing some technical input and output variables of different components of the model algorithm are shown in Table 3-1 below. This highlights the major components of the model. The bulk of the present work will focus on the gas stream profiles, power generation and economic modelling; with emphasis on gas production decline variation and its impact across the entire modules of the framework. The technical inputs to the base modules for this framework as well as environmental and economic parameters can vary causing changes leading to increased level of uncertainty of the framework. Therefore, Monte Carlo simulation (MCS) method is used to carry out risk and sensitivity analysis.

Table 3-1: Base Module, Input and Output Parameters

Input Parameter	Base Module	Output Parameter



<u>Building the Gas Streams Module</u>

Mainly the source of gas for this analysis is the flared associated gas from oil production activities. Estimation of gas streams profiles as well as the gas composition throughout the monetization period is difficult. The irregularity of produced gas stream profile increases as produced associated gas faces decline during the oil filed producing lifecycle. The decline curve equation (DCE) selected to model production profile of gas streams in this study is the harmonic decline curve with different decline rates. The effect of APG production decline on the power production capacity factor is illustrated using the production profile with an initial annual gas production of about 89.5 billion scf undergoing harmonic production decline of different rates is shown in Figure 3-1 below.

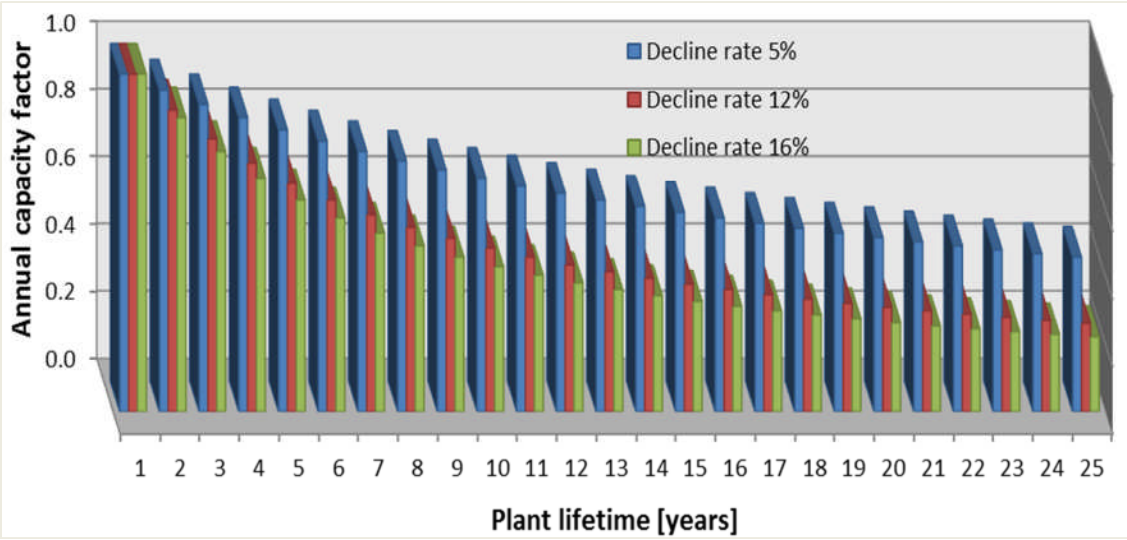


Figure 3-1: Variation of Power Capacity Factor with APG Production Decline

This shows that increasing decline rate has a hostile effect on capacity factor and requires attention. For the scenarios above, the reductions in capacity factor contributed by production decline rate of 5%, 12% and 15% lowers capacity factors to 20%, 30% and 50% respectively. This is explained given that GT engines employed in the gas utilization have a fixed capacity and requires a certain volume flow rate of gas. Apparently, an intermittent resource is introduced by decline which causes resource shortage. This will compel the plant to operate below its rated power output. Again, cost of energy (CoE) generated and eventually the overall economic performance will be affected if intervention is not initiated.

GT Power Module:

From operation point of view, power-plant requires certain level of availability to achieve required capacity factor to meet megawatt-hours in order to generate acceptable revenue at the market price of electricity.

$$\text{Availabilty} \ = 1 - \left(\frac{\mathrm{AN}_{UnplDt} \ - \ \mathrm{AN}_{PlDt}}{8760}\right) \qquad \textit{3-1}$$

Where AN_{UnplDt} and AN_{PlDt} represents the unplanned and planned downtime per year respectively both expressed in hours.

APG decline yields gas supply schedule that is less than the initial quantity required by power-plant at full load, and lowers the capacity factor of the power-plant and availability. This is characterised by redundant power-plant units from the initial capacity of the power-plant. This demonstrated using approximately 1 (one) scf associated gas reserve monetized over 25 years with constant 12% annual production decline rate, see Figure 3-2 below. High availability is vital to economic viability of power plants. Typically for a high efficiency baseload power plant, 1% change in availability will reduce megawatt-hours by 1% annually. This estimated to be between 0.6 to 0.7 point of thermal efficiency which worth approximately 11-14$/kW of capital cost [92].

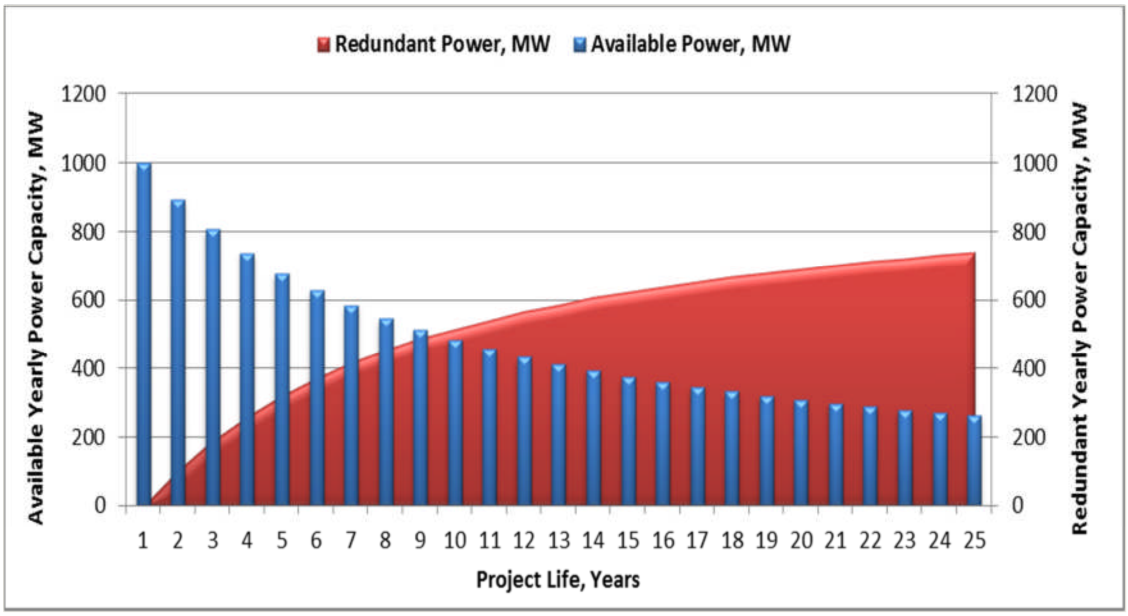


Figure 3-2: Decline Yields Redundant GT Engine Power

In the above illustration about 97.5% of the initial installed capacity becomes redundant at the end of the 25 years of the project operation. This will challenge the power-plant to operate in such a manner to meet the demand of constantly changing fuel schedule as result of depletion of gas production. Part-load operation of power-plant alone may not be robust enough to handle most degree of gas depletion in the absent of makeup-fuel. Other solution to this problem is sorted within power-plant GT engines unit selection. This intent is captured within the power-plant module via combinations of different engine unit capacities and components configurations to form the required megawatt from the initial gas production profile. This study is looking at combination of different options to include:

- Part-load operation
- Makeup-fuel option
- Multiple engine unit with different configurations
- Gas turbine engine unit divestment

The economic module:

To capture all that is required for economic justification; economic module is designed to evaluate different selections of the GT engine units as may be required for particular fuel schedule (APG production profile), and power-plant performance characteristics. Major aspect of the economic module comes from gas turbine performance parameters and other inputs to this module includes the environmental perspective, project financing, tax related costs, site specific conditions which can upset the capital and operating costs of the plant.

3.2 Multiple Engine Unit Specifications

The increasing size of redundant power overtime from the initial power-plant capacity requires multiple engine units so that redundant units can be retired. Power-plant capacities between 15MW to 1000MW are considered for this research with total of eight GTs engine units consisted of 5MW, 10MW, 20MW, 30MW, 50MW, 80MW, 100MW and 200MW capacity ranges. An arrangement of these GT engine fleets to suit periodic decline is another approach of managing redundant power associated with decline called the divestment option.

3.2.1 Engine Divestment Consideration

Redundant GT unit divestment option involves the selection of the GT fleets based on the gas production profile to improve the overall capacity factor of the plant. There are so many techno-economic attributes to the divestment stratagem. The GT fleet selection is done based on the available engines on the library. The engine library contains design point (DP) and off-design (OD) point thermodynamic parameters of the eight GT engine units. Correlation between these engine units both design point and off-design point have been established within the boundaries condition for this study during the engine performance simulation to accelerates the process of divestment process with less simulation. The steps taken during divestment process is summarised in the flow chart as shown below.

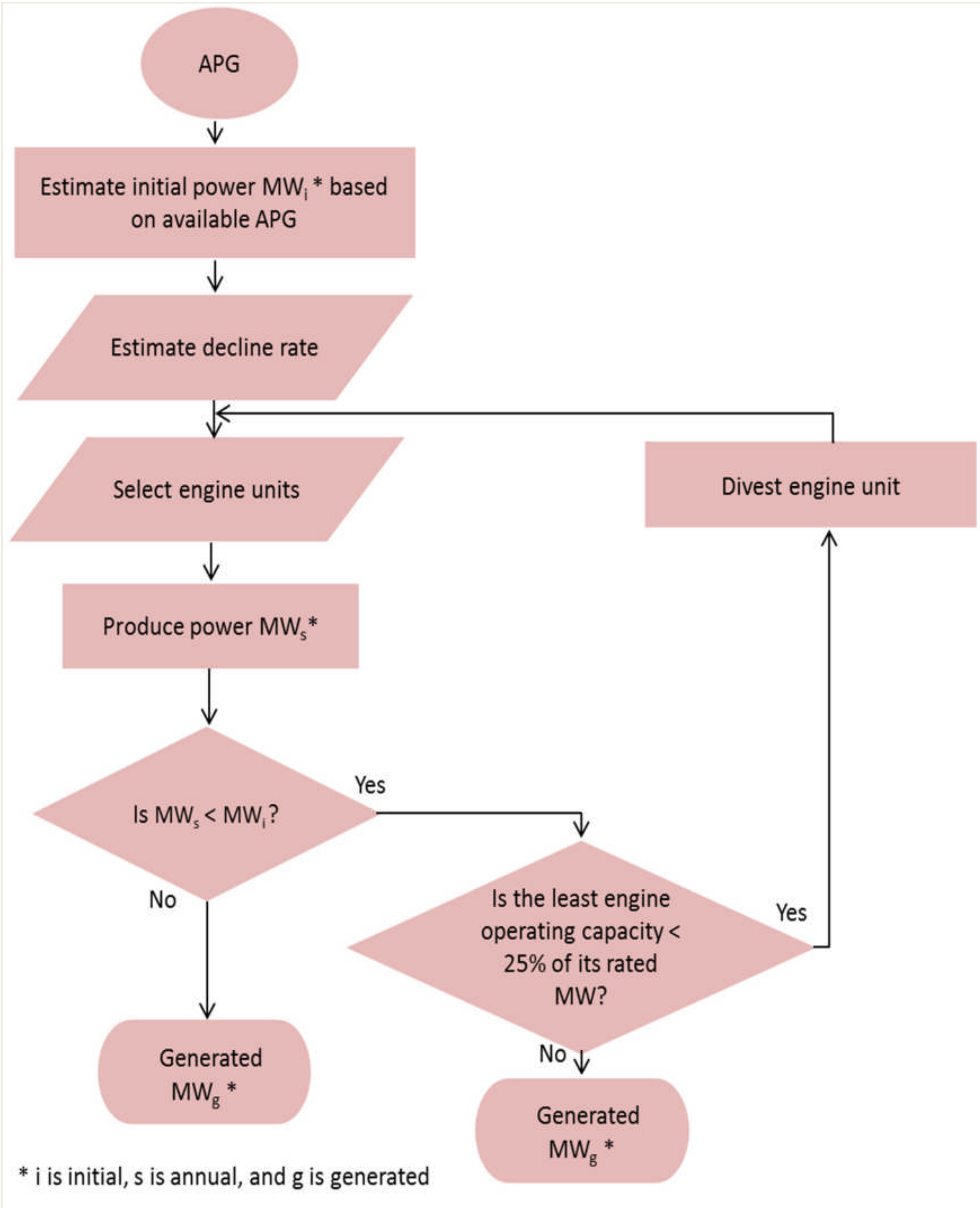


Figure 3-3: Gas Turbine Engine Unit Divestment Algorithm

3.3 GT Engine Units Thermodynamic Modelling and Validation

GT engines for this study are made up of different configurations and output power capacities as listed in section 3.2 above; modelled from existing gas turbine engines data set. Based on a clean natural gas and associated gas compositions, calculation were carried out to obtain the required GT thermodynamic parameters of different engine units selected to form the power-plant engine fleet. Here engine fleets are any combination of gas turbines engine units within the eight GT engines to form a power generation unit.

The GT thermodynamic modelling is carried out using TURBOMATCH code and GasTurb design and performance simulation software. TURBOMATCH is a FORTRAN based code for GT design point (DP) and of-design (OD) performance simulation developed in Cranfield University [93]. GasTurb is commercial software for GTs design and performance simulation [94].

The initial step involves creating fuel data file from the associated gas composition of interest. This was done using the National Aeronautics and Space Administration (NASA) Chemical Equilibrium with Application (CEA) code, (see appendix B). This is followed by creating the input files for each of the GTs being investigated (Appendix B). Once the engine input files are created, GT DP performance simulation is carried out using the clean natural gas as the fuel. This DP simulation result of the modelled GT engine is validated by comparing it with the available DP thermodynamic data similar to the modelled engine from original equipment manufacturer (OEM).

Once the validation of modelled GT engine is completed, another simulation for DP thermodynamic parameters using the created associated gas fuel is obtained. This is used towards producing the engine performance library for associated gas GT utilization for power generation (GTW monetization) techno-economic evaluation. The fuel heating value used for the clean natural gas is 49.736MJ/kg while the fuel heating value based on CEA result for associated gas composition for this study is 45.616MJ/kg.

3.3.1 The 5MW Range GT Engine Unit Modelling and Validation

The 5WM capacity range engine is a single shaft industrial GT engine inspired by Siemens SGT-100 GT engine for power generation application. SGT-100 GTs with power range between 4.5MWe to 5.4WMe has the ability to run on dual-fuel and is suitable for use as a simple cycle, combined cycle, and combined heat and power (CHP) applications [95]. The dual-fuel combustion system attribute of the SGT-100 GTs engine is a good indication for its consideration in this study as one of the engine units for GT utilization of APG scheme. The configuration representing the 5MW range single shaft GT engine is shown below.

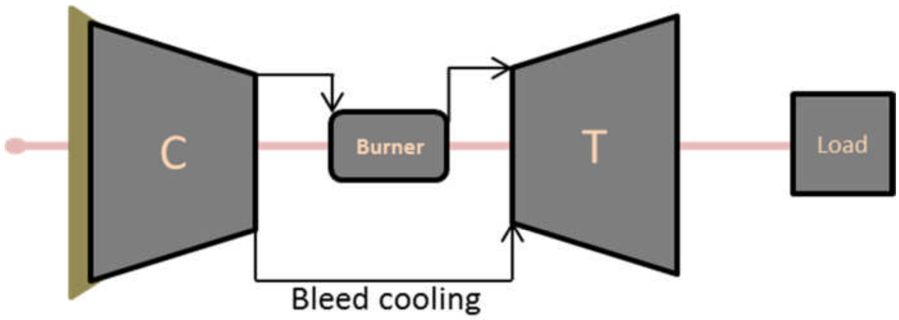


Figure 3-4: Schematic Arrangement for the Single Shaft GT Engine

Table 3-2: Validation of Modelled 5MW Range GT with OEM SGT-100 GT Engine

Parameter	Modelled Engine	SGT-100	Deviation [%]
Power output [MWe]	5.4	5.4	0.0
Heat rate [kJ/kWh]	11436	11613	-1.5
Thermal efficiency [%]	31.0	31.0	0.0
Pressure ratio	15.6:1	15.6	0.0
EGF [Kg/s]	20.6	20.6	0.0
EGT [K]	775.78	804.15	-3. 5
Turbine speed [rpm]	3600	3600	0.0

The validation of the modelled engine DP parameters with the OEM engine available data [95] under ISO condition (288.15K ambient temperature, 101.325 ambient pressure and 60% ambient relative humidity) was conducted at modelled engine DP TET of 1320.5K using clean natural gas see Table 3-3.

Table 3-3: 5MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power output [MWe]	5.4	5.3	0.0
Mass Flow [Kg/s]	20.71	20.71	0.0
Thermal efficiency [%]	31.0	31.0	0.0
Fuel flow [kg/s]	0.322	0.351	0.029
Heating value [MJ/kg]	49.736	45.616	-4.12
Sp. SFC [kg/kWh]	0.230	0.251	+0.12
EGF [Kg/s]	20.6	20.7	+0.02
EGT [K]	775.78	775.78	0.00
NOx severity factor	0.421	0.421	0.00

After validating this engine, the engine is run using the created associated gas fuel. Most DP parameters of this engine using clean natural gas fuel and the associated gas fuel are presented in Table 3-4 below.

The DP parameters are pretty much the same for the two fuels, with major variation in fuel flow and shaft power specific fuel consumption (Sp. SFC) corresponding to the lower heating value of the APG compared to clean natural gas with higher heating value. However, impurities in the APG could result to degraded performance of the engine and increased emission.

Table 3-4: 5MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power output [MWe]	5.4	5.3	0.0
Mass Flow [Kg/s]	20.71	20.71	0.0
Thermal efficiency [%]	31.0	31.0	0.0
Fuel flow [kg/s]	0.322	0.351	0.029
Heating value [MJ/kg]	49.736	45.616	-4.12
Sp. SFC [kg/kWh]	0.230	0.251	+0.12
EGF [Kg/s]	20.6	20.7	+0.02
EGT [K]	775.78	775.78	0.00
NOx severity factor	0.421	0.421	0.00

3.3.2 The 12MW Range GT Engine Unit Modelling and Validation

The 12MW engine range is a heavy duty single shaft industrial gas turbine inspired by GE10 gas turbines. GE10 is a General Electric gas turbine in the 12 MW range, normally available as a single or two-shaft configuration. This engine has been used for different applications to include power generation as

(GE10-1) and mechanical prime mover (GE10-2) and is capable of burning wide range of gaseous and liquid fuels, including low BTU gas and hydrogen [96], options which suggest it a suitable candidate for GTW APG utilization in this study.

Table 3-5: 12MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine	GE10-1 Engine	Deviation [%]
Power output [MWe]	11.26	11.25	+0.09
Mass Flow [Kg/s]	47.0	47.0	0.0
Thermal efficiency [%]	31.4	31.4	0.0
Pressure ratio	15.5:1	15.5	0.0
EGF [Kg/s]	47.16	47.5	-0.72
EGT [K]	766.19	755.15	+1.46
Turbine speed [rpm]	1100	1100	0.0

Validation of the DP parameters of the modelled engine using the General Electric GE10-1 variant under ISO condition based on available data [97] is shown in Table 3-5 above. The modelled engine DP TET is 1364K and clean natural gas quality with 49.736 MJ/kg heating value. For other engine DP parameters of the modelled engine see full engine simulation data Appendix B.

The DP parameter of the modelled engine match pretty much with GE10-1 engine, with a trivial increase in the exhaust gas temperature (EGT) and power output of the modelled engine. Again the exhaust gas flow (EGF) of the modelled GT is slightly lesser than the GE10-1 GT. Comparing the DP of this engine with the two fuels Table 3-6 below, the major variation are seen in fuel flow, exhaust gas flow and shaft power specific fuel consumption (Sp. SFC) corresponding to the lower heating value of the APG compared to the clean natural gas. However, impurities in the APG could result to degraded performance of the engine as well as increased emission.

Table 3-6: 12MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power [MW]	11.26	11.24	-0.02
Mass Flow [Kg/s]	47.0	47.0	0.00
Thermal efficiency [%]	31.4	31.4	0.00
Fuel flow [kg/s]	0.721	0.785	+0.06
Heating value [MJ/kg]	49.736	45.616	-4.12
EGT [K]	766.19	766.19	0.00
SFC [kg/kWh]	0.231	0.252	+0.02
EGF [Kg/s]	47.16	47.23	+0.07
NOx severity factor	0.403	0.403	0.00

3.3.3 The 20MW Range GT Engine Unit Modelling and Validation

The 20MW range GT engine belongs to the aeroderiavtive family with three spool inspired by Roll-Royce RB211(G26 variant) power generation GT engine. RB211 engine can run both liquid and gaseous [98], a dual fuel chararctiristics and its configuration incresed it chance to be considered in this study.

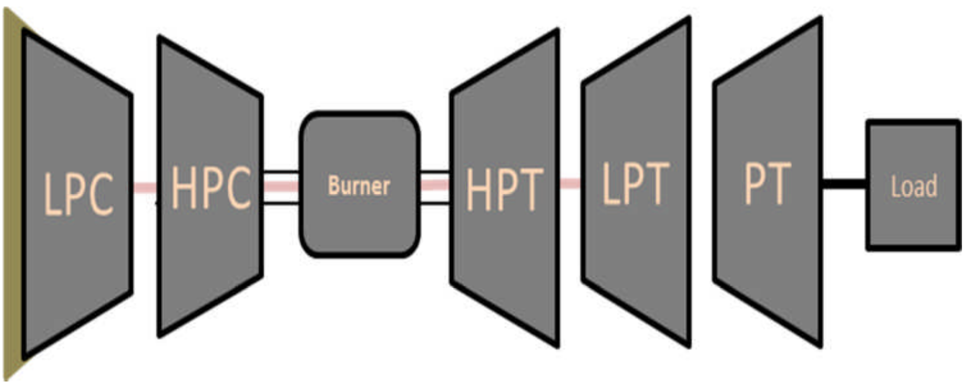


Figure 3-5: Layout of the Three Shaft GT Engine

The 20MW range GT engine DP parameter validation was carried out using available data from [99] under ISO condition with clean natural gas. The modelled engine has an overal pressure ratio (PR) of 20.2:1 and TET of 1461.7K. the parameters for both engines are shown in Table 3-7 below with trivial divation in exhaust gas flow and heat rate. This could have probably occurred because the heat rate from OEM data used for this modelling seems to be an average heat rate for all the RB211 engine variants. Comparing the DP result of the modelled engine for clean natural gas and associated gas case, there is a slight variation in engine power output, with major diference in fuel flow see Table 3-8 below.

Table 3-7: Validation of Modelled 20MW Range GT Engine Nominal Performance

Parameter	Modelled Engine	G26	Deviation [%]
Power output [MW]	27.26	27.26	0.00
Heat rate [kJ/kWh]	9892	9898	-0.06
Thermal efficiency [%]	36.4	36.4	0.0
Pressure ratio	22.2:1	-	-
EGF [Kg/s]	91.3	91.3	0.0
EGT [K]	759.84	774.15	+1.93
Turbine speed [rpm]	4800	4800	0.00

Table 3-8: 20MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power [MW]	27.6	27.2	-0.4
Mass Flow [Kg/s]	90.5	90.05	0.00
Thermal efficiency [%]	36.4	36.4	0.00
Fuel flow [kg/s]	1.504	1.639	+0.135
Heating value [MJ/kg]	49.736	45.616	-4.12
EGF [Kg/s]	91.3	91.5	+0.2
EGT [K]	759.84	759.79	-0.05
NOx severity factor	0.504	0.504	0.00

3.3.4 The 30MW Range GT Engine Unit Modelling and Validation

The 30 MW range is an aeroderivative heavy duty gas turbine inspired by GE PGT25+ gast turbine for power generation application. This machine is a two shaft GT with a free turbine, the high preesure turbine (HPT) drives the low pressure or booster compressor (LPC) and high pressure compressor (HPC) Figure 3-6 below.

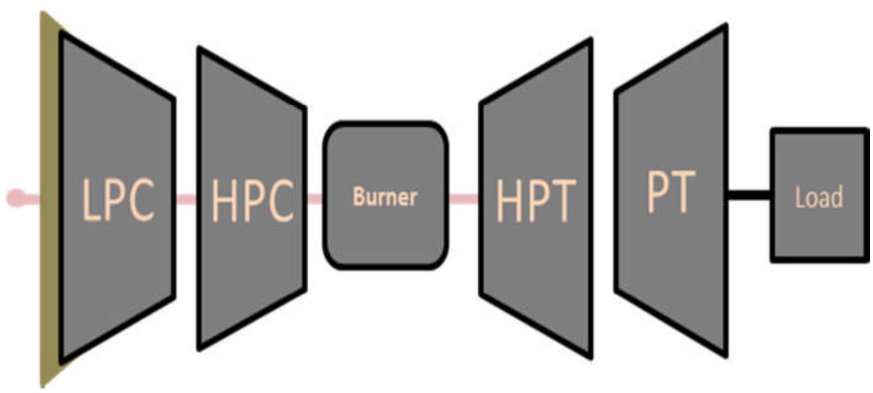


Figure 3-6: The Layout of the Two Shaft GT Engine with Free Power Turbine

The PGT25+ is capable of operating on dual-fuel and good for part-load operation with moderate variation in its efficiency, hence is included the in engine fleet for this study.

The validation of the DP parameter with the available OEM data [96] is presented in Table 3-9 below while the difference between most DP parameter of the modelled runing on clean natural and APG is outlined in Table 3-10 below. Again the highest deivtaion observed runing this engine with these two fuels is on the fuel flow.

Table 3-9: Validation of Modelled 30MW Range GT Engine Nominal Performance

Parameter	Modelled Engine	PGT25+	Deviation [%]
Power [MW]	30.225	30.266	-0.14
Thermal efficiency [%]	39.5	39.6	-0.25
Pressure ratio	24.0	24.0	0.00
EGF [Kg/s]	91.1	84.3	+8.07
EGT [K]	755.12	733.15	+1.46
Turbine speed [rpm]	6100	6100	0.00

Table 3-10: 30MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power output [MW]	30.225	30.189	-0.036
Mass Flow [Kg/s]	89.699	89.699	0.00
Thermal efficiency [%]	39.5	39.5	0.00
Fuel flow [kg/s]	1.54	1.68	+0.14
Heating value [MJ/kg]	49.736	45.616	-4.12
EGF [Kg/s]	91.1	91.2	+0.10
EGT [K]	755.12	755.11	-0.01
NOx severity factor	0.852	0.852	0.00

3.3.5 The 50MW Range GT Engine Unit DP Modelling and Validation

The 50MW range is a signle shaft industrial gas turbine inspired by Siemens gas turbine SGT-800. Fuel flexiabily, wide range of operating conditions and hign cycle efficiency [95] are among factors that makes this engine choice in this study. The DP parameters of this engine at TET of 1506K is used to validate the OEM DP parameters. comparison of DP parameters running clean and assoacited gas is also presented in Table 3-12 below.

Table 3-11: Validation of Modelled 50MW Range GT Engine Nominal Performance

Parameter	Modelled Engine	SGT-800	Deviation [%]
Power output [MW]	50.5	50.5	0.00
Thermal efficiency [%]	38.9	38.3	+1.57
Pressure ratio	21.1	21.1	0.00
EGF [Kg/s]	134.1	134.2	-0.07
EGT [K]	825.8	826.2	-0.05
Turbine speed [rpm]	6608	6608	0.00

Table 3-12: 50MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power output [MW]	50.54	50.48	-0.06
Mass Flow [Kg/s]	131.69	131.69	0.00
Thermal efficiency [%]	38.3	38.3	0.00
Fuel flow [kg/s]	2.614	2.848	+0.23
Heating value [MJ/kg]	49.736	45.616	-4.12
Power. SFC [kg/kWh]	0.186	0.203	+0.12
EGF [Kg/s]	134.1	134.3	+0.02
EGT [K]	825.8	825.8	0.00
NOx severity factor	0.629	0.629	0.00

3.3.6 The 80MW Range GT Engine Unit DP Modelling and Validation

The 80MW range ouput power capacity is a single shaft indurtial GT engine inspired by GE MS700EA GT engine. The valiadtion of the modelled engine DP parameter is done as shown in Table 3-13 below. The clean natural gas DP parameter is compared with the APG fuel DP parameter in Table 3-14 below.

Table 3-13: Validation of Modelled 80MW Range GT Engine Nominal Performance

Parameter	Modelled Engine	MS7001EA	Deviation [%]
Power output [MW]	85.1	85.1	0.0
Thermal efficiency [%]	32.64	32.7	-0.180
Pressure ratio	12.7	12.7	0.00
Mas flow [kg/s]	229.0	299.0	0.00
EGT [K]	818.21	810.15	+0.9
Turbine speed [rpm]	3600	3600	0.00

Table 3-14: The 80MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power [MW]	85.1	85.0	-0.1
Mass Flow [Kg/s]	229.0	229.0	0.00
Thermal efficiency [%]	32.64	32.62	0.00
Fuel flow [kg/s]	5.243	5.714	+0.471
Heating value [MJ/kg]	49.736	45.616	-4.12
Power. SFC [kg/kWh]	0.222	0.242	+0.02
EGF [Kg/s]	303.35	303.82	+0.47
EGT [K]	818.21	818.20	0.01
NOx severity factor	0.283	0.283	0.00

3.3.7 The 100MW Range GT Engine Unit DP Modelling and Validation

The 100MW range GT engine is a three shaft intercooled aeroderivative machine see Figure 3-7 inspired by GE LMS100 engine. This GT engine maintains high thermal efficiency and operates with dual fuel [96]. Among the reasons for choosing this engine configuarion included its ability to offer high efficiency at part-load operation, envisaged to be of great advantage during the initial APG decline stages.

The modelled engine DP TET is 1489.9K. Validation of the DP parameters of the modelled engine using the GE LMS100 under ISO condition based on available data [96] is shown in Table 3-15 below. DP parameters of the modelled engine match with the OEM ISO specifications, with slight reduction in the thermal efficiency and EGF. Again comparing DP parameters of the clean natural gas fuel with the associated gas fuel there is deviations with more seen on the fuel flow Table 3-16 below like in very other engine DP parameter.

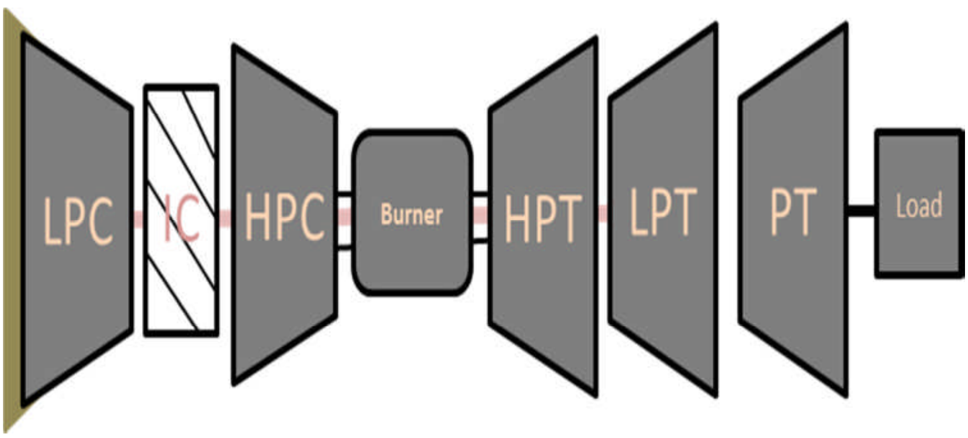


Figure 3-7: The layout of the Intercooled Free Power Turbine Engine

Table 3-15: Validation of the Modelled 100MW Range GT Engine

Parameter	Modelled Engine	LMS100	Deviation [%]
Power [MW]	98.178	98.196	-0.018
Heat rate [kJ/kWh]	7932	7997	-0.81
Thermal efficiency [%]	45.0	45.0	0.00
Pressure ratio	40.0	40.0	0.00
EGF [Kg/s]	206.9	206.9	-0.00
EGT [K]	703.96	690.15	-2.00
Turbine speed [rpm]	3600	3600	0.00

Table 3-16: 100MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power [MW]	98.178	98.067	-0.111
Mass Flow [Kg/s]	202.9	202.9	0.00
Thermal efficiency [%]	45.0	45.0	0.00
Fuel flow [kg/s]	4.349	4.740	+0.39
Heating value [MJ/kg]	49.736	45.616	-4.12
Sp.SFC [kg/kWh]	0.160	0.174	+0.014
EGF [Kg/s]	206.9	207.3	+0.40
EGT [K]	703.96	703.96	0.00
NOx severity factor	0.512	0.512	0.00

3.3.8 The 200MW Range GT Engine Unit DP Modelling and Validation

The 200MW range GT engine is inspired by Alstom GT13E2. Fuel flexibility of the GT13E2 burning every natural gas copmosition [64], combined with its high efficecny. Validation of the modellled Gt engine with DP TET of 1420K was carried out using OEM data [100] and the result is shown Table 3-17 below ; while comparing running the modelled engine using clean natural gas and APG fuel is shown in Table 3-18 below.

Table 3-17: Validation of the Modelled 200MW Range GT

Parameter	Modelled Engine	GT13E2	Deviation [%]
Power output [MW]	202.6	202.7	-0.05
Thermal efficiency [%]	38.0	38.0	+1.57
Pressure ratio	18.2	18.2	0.00
EGF [Kg/s]	624	624	0.00
EGT [K]	772.02	774.15	-0.28
Turbine speed [rpm]	3600	3600	0.00

Table 3-18: 200MW Range DP Parameter Comparison of Running APG and NG

Parameter	Modelled Engine		Deviation
	Clean Natural Gas	Associated Gas	
Power output [MW]	202.6	202.4	-0.2
Mass Flow [Kg/s]	621.0	621.0	0.00
Thermal efficiency [%]	38.0	38.0	0.0
Fuel flow [kg/s]	10.743	11.707	+0.96
Heating value [MJ/kg]	49.736	45.616	-4.12
SP.SFC [kg/kWh]	0.191	0.208	+0.17
EGF [Kg/s]	624	625	+1.0
EGT [K]	772.02	772.00	-0.02
NOx severity factor	0.451	0.451	0.000

In summary, the selection and modelling of eight (8) different gas turbine engine configurations for associated gas utilization has been completed. Together with the validation of DP data of the modelled engine units with gas turbine engines original equipment manufacturer's data. Also changes in running the modelled gas turbine engines on associated gas have been performed as need for subsequent part of this study. There is no significant change observed between pure natural gas and the associated gas, except for the fuel flow variation of about 7.6% to 9% across the entire engine fleet.

3.4 Gas Turbine Engine Performance Data Correlation

The gas turbine DP performance simulation is helpful to evaluate the performance parameter of the modelled engine against the OEMs data to increase the chances of the modelled engine being close to the one being studied.

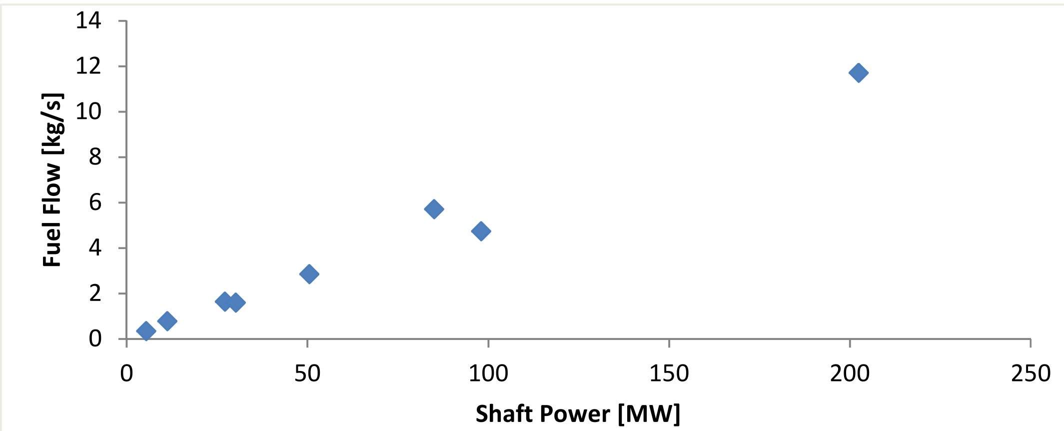


Figure 3-8: Fuel Consumption and Power Output Correlation at DP

The DP produced power and fuel flow shows a high postive correlation with fule incresing power is increaseing as would expected. Performance of all the eight individual GT engine units selected for this study are used to form equation linking the amount of gas being utilized to operating conditions of the GTs. The annnual volume of associated gas utilized for a given power output for the GT engine fleet via DP formance parameters consideration is calculated from equaition *3-2*.

$$\boldsymbol{AG_V} = 1102242416.4PL_f\left(\frac{0.0571P_{MW} + 0.0303}{\rho}\right) \qquad \textit{3-2}$$

Where $\boldsymbol{AG_V}$ is the volume of AGP utilized per annum (scf/year) at the DP power ouput P_{MW} (MW); ρ is desity of the APG (kg/m^3) and PL_f is plant load factor.

3.4.1 Operating Environment Envelope

Most life of GT engine in operation is spent in environment far from the DP conditions. Evaluation of cost of power generation techology requires performce data of the power-plant in that specific condition under considretaion. Technically, such performance data linked with power-plant operations evaluation will include thermal efficiency or heat rate, fuel consumption, and output power capcity of GT among others.

<u>Effect of Ambient Temperature</u>

The effect of ambient temperature changes GT performance significantly. In this study a typical temperature profile of a location in Niger-Delta region of Nigeria where the country's APG is mostly predominant is selected to represent ambient site temperature profile, Figure 3-9 below. This choice reflects performance of GT engine in a typical associated gas utilization site.

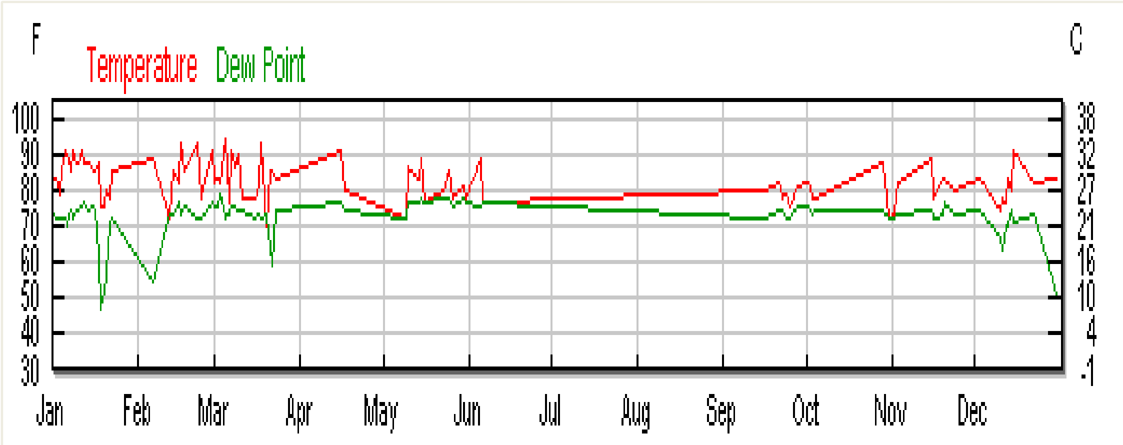


Figure 3-9: Site Monthly Temperature Profile; January–December 2010 [101]

The site temperature is considerably high compared to GT DP temperature; reaching about 24^0C (297.15K) above the DP temperature in May. Temperature fluctuates more around December to June and remains somewhat stable between June to November.

The effect of ambient temperature on performance of a gas turbine engine based on the chosen location is demonstrated in Figure 3-10 below.

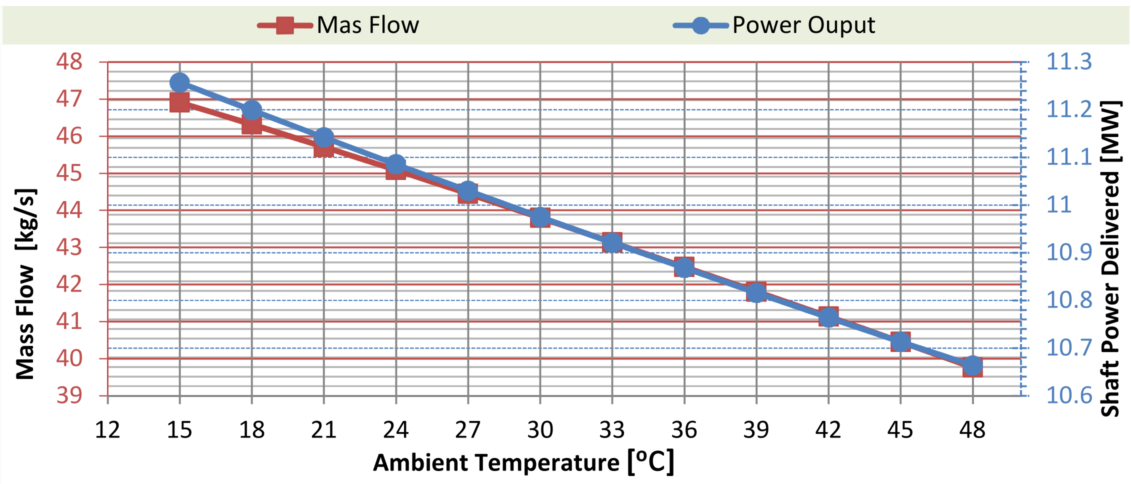


Figure 3-10: Variation of Engine Mass Flow and Power with Ambient Temperature

Figure 3-10 above, shows effect of high ambient temperature on performance of GT engine using the single shaft 12MW range GT engine operating at sea level and constant spool speed of 1100rpm and DP or initial operating pressure ratio (OPR) of 15.5:1.

On a hot day, increase in temperature decreases air density and reduce mass of air entering the GT engine. Similarly, compressor OPR decreases (see Figure 3-10 above) consequently leading to lower thermal efficiency and power output at constant engine rotational speed. However, in contrast to cold day, more shaft power is produced because lower temperature increases the density of air thereby increasing the mass of air entering the compressor for a given engine rotational speed..

The compressor operating line represented in Figure 3-11 with “yellow squares” shows a decrease in OPR and mass flow caused by an increase in the ambient temperature as well as speed reduction afterwards.

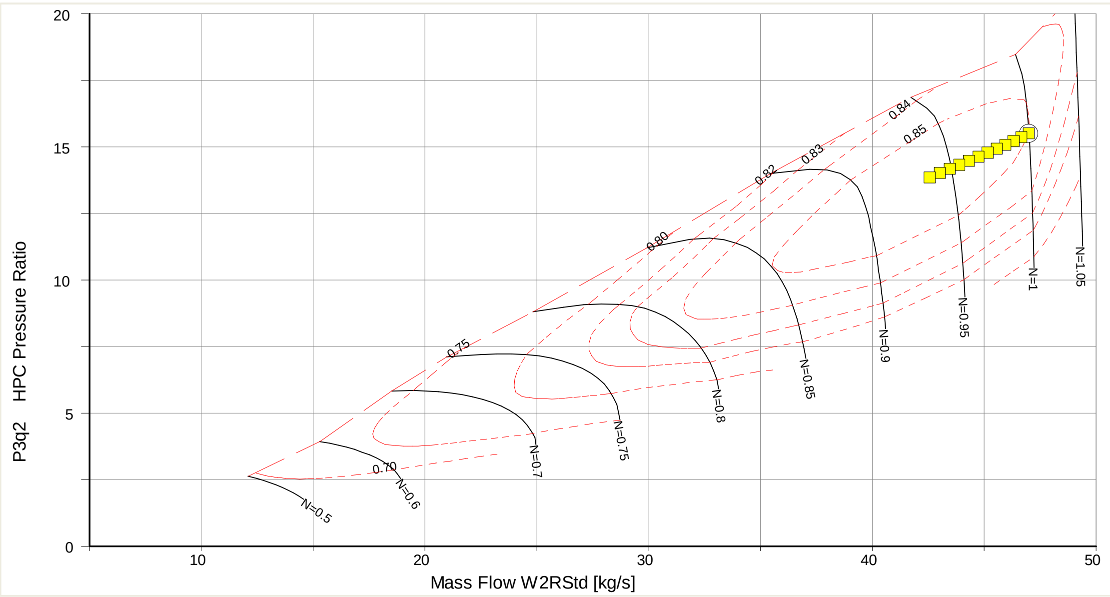


Figure 3-11: Hot Day Temprature on GT Engine Compressor Operation

The effect of ambient temperature on engine performace accros entirely engine units for this study using ambient temperature range of 292.15K (19^{o}c) to 321.15K (48^{o}c) in the profile as shown in Figure 3-12 below is adopted. However, this temperature profile is asumeed to be the same throughout the year to reduce computational time. Then using equation (*3-3*) after simulating the engines within this profile annual power production for any engine combination is calculated.

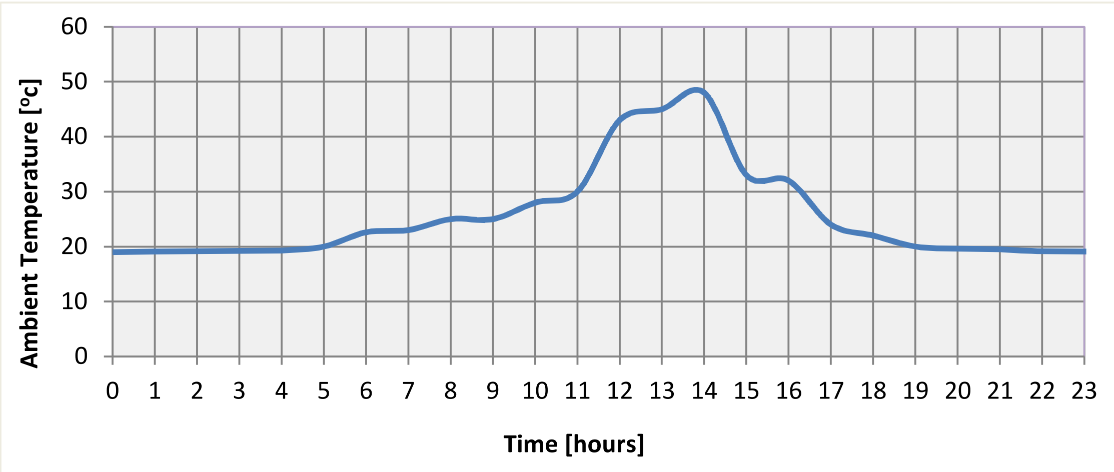


Figure 3-12: Hourly Ambient Temperature Representing Site Temperature Profile

$$AGTEFMW_P = \sum_{n=1}^{n} \left(\sum_{t=0}^{t=23} \frac{P_{Hr}}{24} \right) 8760\, PL_f \qquad \textit{3-3}$$

Where $AGTEFMW_P$ is annual GT engine fleet power produced (MW); n is the number of GT engine unit; P_{Hr} is power produced (MW) per time t (hours) and PL_f is fleet load factor (fraction).

3.4.2 Makeup-Fuel Option

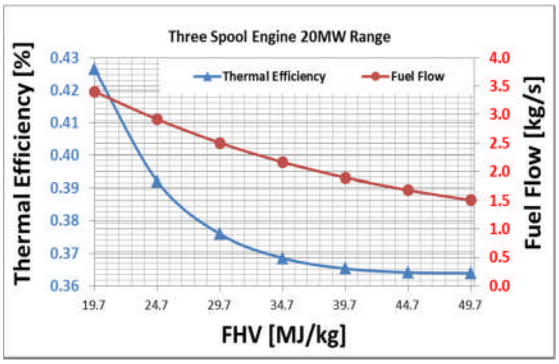
Gas turbine engines deployed for on-site utilization of flared associated gas may strive to meet consistent fuel supply schedule. This is as a result of associated gas production depending on oil production operations coupled with uncertainty associated with production decline. Whereas GT engines required certain level of availability to meet MW hours to generate acceptable revenue at market price of electricity, thus GT engine operation control and/or makeup-fuel option is inevitable for onsite gas turbine utilization of APG.

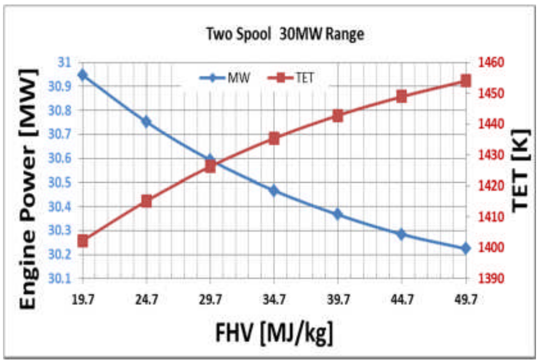
However, running other fuels on gas turbines that was initially designed for natural gas can result to variation in thermodynamic performance and emissions, thus requiring modification of the gas turbine engine [102-106].

The consideration of other source of fuels to augment associated gas during its production decline, leads to stimulation of the GT engine units for lower calorific fuels. These low calorific fuels can be used to represent any of the cheap fuels including those derived from crude oil and others source of fuels favoured by logistics and other parameters employed in assessing a particular GTW monetization scenario.

The simulation of the engine units, to unveil their performance with the low BTUs fuel is shown below in Figure 3-13 (a-d). This is done by using fuel heating value (FHV) as handle during an OD performance parametric study on the selected GT engine units.

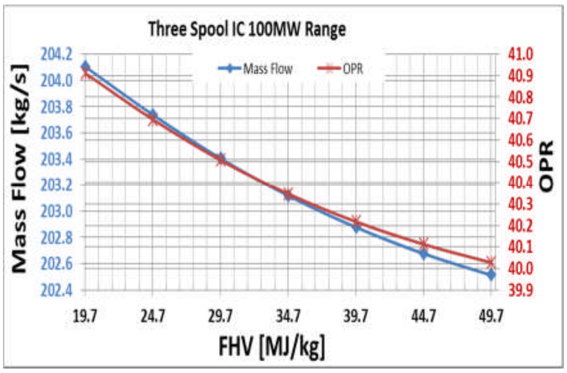
The selected engines in this case included: (a) the 20MW range three shaft with a free turbine. The configuration is such that the LPC and HPC are driven by LPT and HPT respectively. This engine is used to demonstrate the effects of FHV on thermal efficiency and fuel flow. (b) The second engine is a 30MW range gas turbine engine with two shaft arrangement having a free power turbine. The gas generator of this engine comprises of LPC, HPC and HPT. This is used to show effects of FHV on shaft power delivered and turbine entering temperature (TET). (c) The third gas turbine engine is a 100MW range three shaft with intercooler. This engine is used to demonstrate the effect of low FHV on engine mass flow and overall operating pressure ratio (OPR).

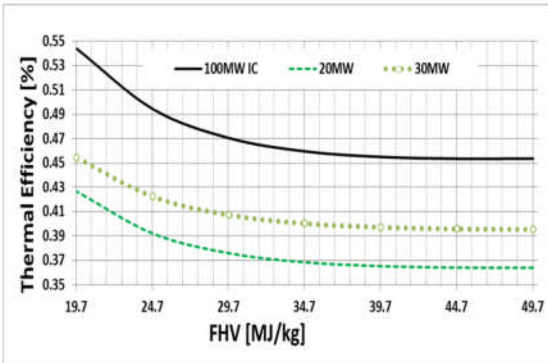




(a) FHV, Thermal Efficiency and Fuel Flow

(b) FHV, Power Output and TET





(c) FHV, Mass Flow and OPR

(d) FHV and Thermal Efficiency

Figure 3-13: Effect of Varying Fuel Heating Value on Gas Turbine Engines

The simulation of GT engine performance using a FHV as handle at a given engine speed shows a fall in heating value of fuel follows an increase in gas turbine engine thermal efficiency and power output. This could be attributed to the observed increasing engine mass flow and OPR. However, from the gas turbine operation and design point of view, the major concern is that compressor surge margin will be affected at this sort of pressure and flow without any modifications to GT engines. Again these lower BTU fuels especially the crude oil, its heating and degasification safety requirements as well as density, viscosity and flashpoint requires attention in accordance with regulations [106].

3.4.3 GT Engine Part-load Operation

Considering the fact that fuel supply deplete over time whereas gas turbine engine is deployed based on volume of associated gas at commencement of the project may require some of the engine units to run on part-load during the early stage of the decline. This is envisaged to be one of the ways to manage associated gas production decline during its utilization on gas turbine when there is no other source of fuel and logistics does not favour such a small change in fuel schedule.

The part-load operation or performance is the variation of specific fuel consumption with reduction in power output. This is of great importance when running on lower power setting is being considered.

In general, gas turbine for electric power generation normally operates in lower power setting for considerable time frame. Irrespective of the gas turbine engine configuration, operating on lower power generally degrades the engine performance. However engine configuration could have a lot of benefit in this regards as shown in Figure 3-14 below. Most gas turbine engine for power generation application employs single shaft engine configuration since the speed of the electric generator is constant. This has its advantage as in the case of load shed where compressor can efficiently act as a brake.

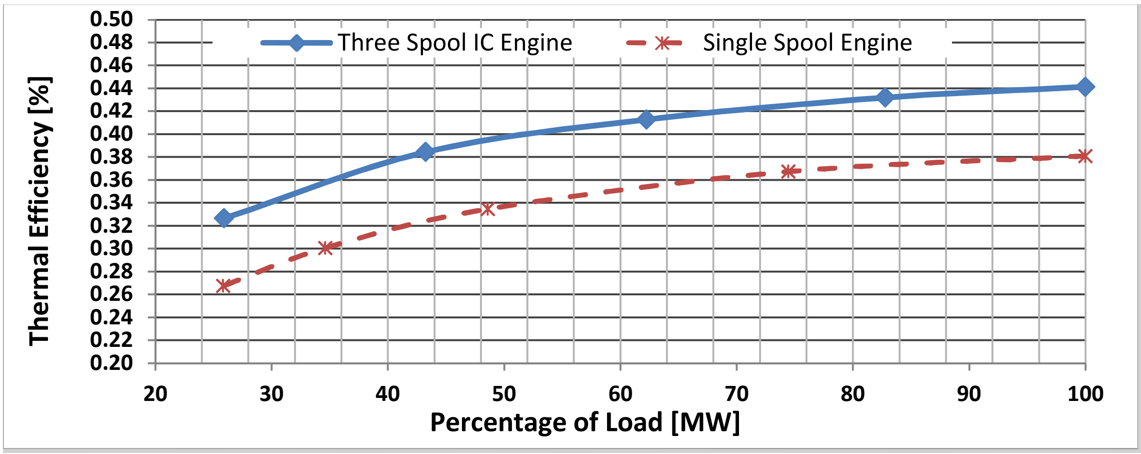


Figure 3-14 Comparison of Part-load Performance of Engine Configuration

Apparently, the three spool intercooled aeroderivative engine configuration displays a better thermal efficiency during part-load operations compared to the single shaft engine configuration. The GT engine configurations in this study were selected to harness the advantages of different engine configurations. The single shaft unit have larger power output capacity anticipated to run most of the time while the aeroderivative engines with multiple shafts will be deployed based on consideration of redundant engine units and part-load operations.

3.5 Economic Model

The economic model comprises the various codes for cost estimate and project appraisal approach for evaluating the viability of the project. The cost component includes capital project cost, fuel cost, operating and maintenance (O&M) cost, taxes, etc.

3.5.1 Cost Estimation

Capital Cost

The capital cost estimation started with the purchased equipment cost (PEC) based on power output and thermal efficiency (heat rate). Other cost elements to include civil/structural, installation cost, piping and materials are all considered afterwards as listed in Table 3-19.

The sum of these cost and the PEC is called fixed capital investment (FCI). Addition of indirect cost component and other outlays to FCI presents the total capital investment (TCI) often called the total project engineering, procurement and construction (EPC) cost. Cost estimates were done in 2010 British pounds sterling assuming the so-called “overnight” capital cost basis.

Overnight cost is as an estimate of cost which assumes the plant construction is done in a single day from planning to completion. Its advantages include the fact that it helps to avoid the impact of financing issues and assumptions on estimated cost [107].

The purchased equipment cost (PEC) of gas turbine units found in literature is a function of both the rated engine output capacity and thermal efficiency (heat rate). As such, PEC data found in the literature [108] (see appendix c) was first selected to match closely the efficiency and capacity of the engine units being considered. Then the price of these selected engine units are converted to 2010 British pound sterling value through the UK GDP deflator [109] and annual currency exchange-rate [110].

The updated currency is therefore used with the capacity of interest representing each of the eight (8) engine units is scaled appropriately as summarised in Table 3-20, using a generic scaling relation [111] as:

$$\mathrm{PEC\ R} = \mathrm{PEC}\ R_o \times \left({}^{S}/_{S_o} \right)^f \qquad \textit{3-4}$$

in which the $\mathrm{PEC\ R}$ of a GT unit of size S is related to $\mathrm{PEC}\ R_o$ of the reference GT unit size S_o by means of a scaling factor f as 0.67.

Table 3-19 Guide for Breakdown of Total Capital Investment (TCI) [91]

		Typical Values	Study Estimation
I. Fixed capital investment (FCI)	**A: Direct Cost, DC**		
	1. Onsite Cost (ONSC)		
	* Purchased equipment cost (PEC)	15-40% of FCI	Based on power output and thermal efficiency, see [108]
	* Purchased equipment installation	20-90% of PEC; 6-14% of FCI	50% of PEC
	* Piping	10-70% of PEC; 3-20% FCI	25% of PEC
	* Instrumentation & control	6-40% of PEC; 2-8% of FCI	included PEC
	* Electrical equipment & materials	10-15% of PEC; 2-10% of FCI	12% of PEC
	2. Offsite costs (OFSC)		
	* Land	0-10% of PEC;0-2% of FCI	9% of PEC
	* Civil, structural & architectural work	15-90% of PEC; 5-23% of FCI	30% of PEC
	* Service facilities	30-100% of PEC; 8-20% of FCI	15% of PEC
	B: Indirect Cost, IC		% of DC
	1. Engineering & supervision	25-75% of PEC;6-15% of DC; 4-21% of FCI	30% of PEC
	2. construction cost	15% of DC; 6-22% of FCI	
	3. Contingencies	8-25% of sum above costs; 5-20% of FCI	
II. Other outlays	A. Start-up cost	5-12% of FCI	25% of PEC
	B. Working capital	10-20% of TCI	
	C. cost of licencing, R&D		
	D. Allowance for fund used during Construction (AFUDC)		

Table 3-20: Estimated EPC of Simples Cycle GT Engine Units

Engine Units #	Blaseload Rating (MW)	Thermal Efficiency (%)	Reference Plant Information*				Estimated PEC (£/kW)
			Thermal Efficiency (%)	Blaseload Rating (MW)	Genset Plant Price ($)	Specific Plant Price ($/kW)	
1	5.40	31.0	30.5	5.3	2029500	398.6	300.7
2	11.20	31.4	32.5	10.7	400000	374.2	287.6
3	27.26	36.4	36.0	29.1	849000	292.2	208.5
4	30.27	39.6	39.3	32.1	10300000	320.7	229.8
5	50.5	38.3	38.4	51.4	14800000	288.2	212.3
6	85.1	32.7	32.8	85.4	16600000	194.4	144.6
7	98.20	45.0	42.2	51.9	16200000	312.0	356.4
8	202.7	38.0	38.2	270.3	43200000	159.8	98.2

* Reference plant price [108] 2003 USD

The specific PEC (£/kW) as estimated decreases with an increasing plant capacity and for similar plant capacities, the higher efficiency engine have higher specific PEC (£/kW). This is due to the increased components required to achieve such high efficiency. Thus, engine number-7 with 45.0% thermal efficiency and 98.20MW has a higher specific PEC (£/kW) cost compared to engine number-6 with 32.7% thermal efficiency and 85.1MW making it the highest among all the engine units in this study.

The TCI cost of the plant based on any given combination of the engine units is calculated by adding the appropriate PEC of the associated gas turbine engine units and using Table 3-19 accordingly.

The calculated TCI cost so far is still only a deterministic value. However, due to the fact that this study focused on probabilistic method, a curve fitting on the list of the specific price of the engines in [108] to find the probability distribution for probabilistic estimation using [112] gives a triangular distribution Figure 3-15. The calculated deterministic value of TCI is used as the most likely value together with other statistical parameters from Figure 3-15 to build specific TCI cost probability distribution used in the probabilistic analysis.

In the distribution chart below, the columns is the input data (specific plant price, £/kW) and the line is the curve fitted distribution. The fit comparison Figure 3-16 shows the best five distributions for the given input set using statistical ranking, is the triangular, followed by uniform, weibull, normal and logistic distributions.

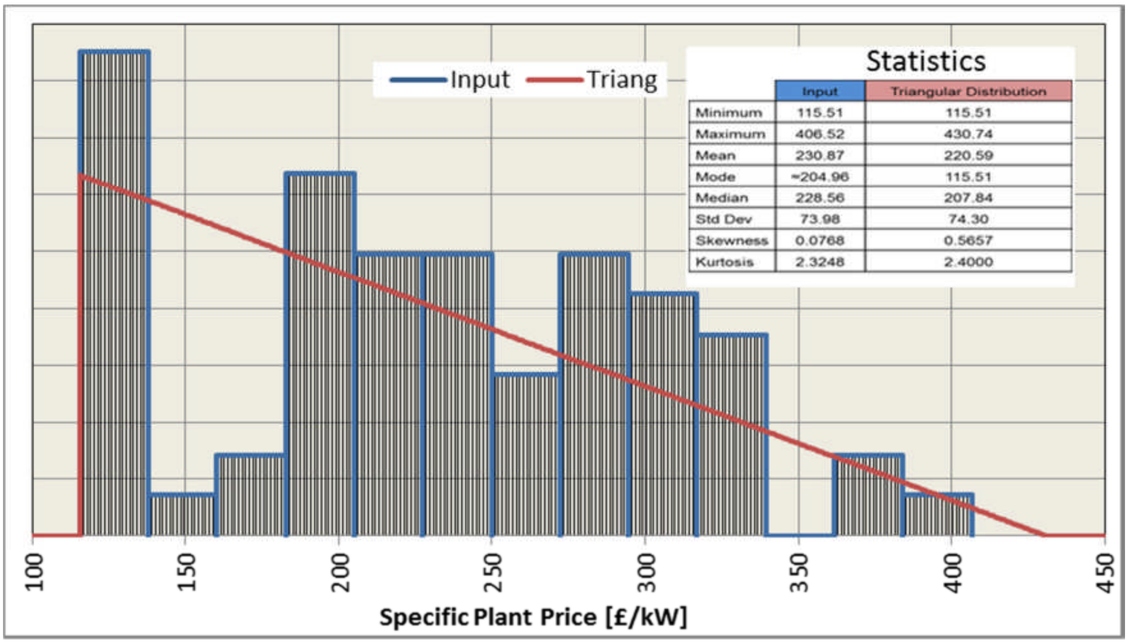


Figure 3-15: Distribution Fit for Specific Plant Price

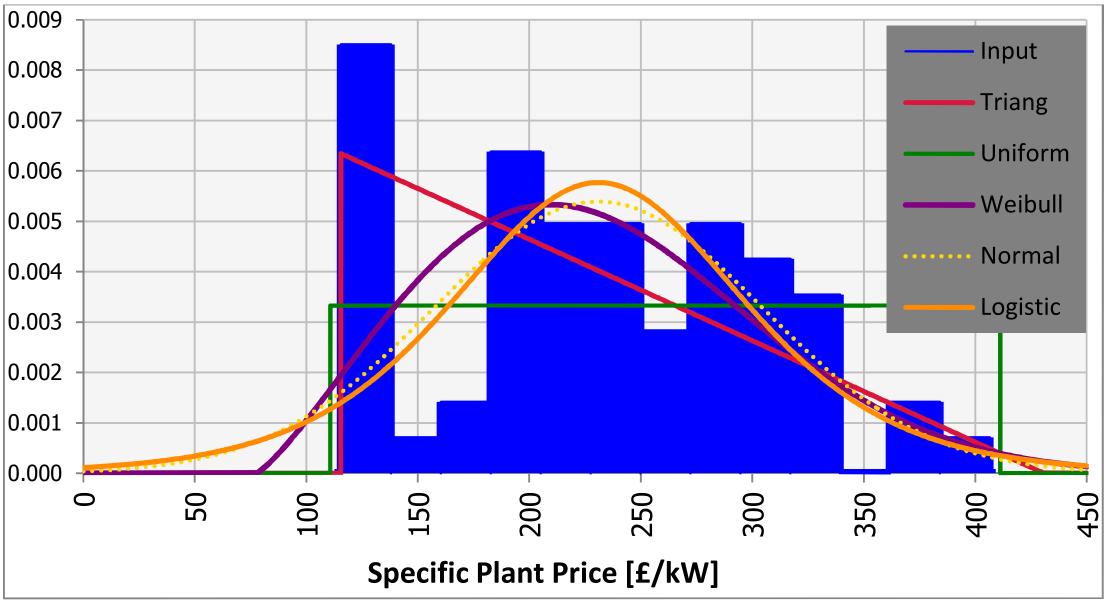


Figure 3-16: Fit Comparison for Specific Plant Price Figures

<u>Fuel, Operation and Maintenance Cost</u>

Fuel cost is separated from operation and maintenance (O&M) cost. Wellhead gas price is used for gas production costs with premium addition to compensate for the minimal required field processing. Natural gas wellhead price extracted from the US Energy Information Admiration (EIA) is used for this and for the purpose of determining the fuel cost distribution as required for the probabilistic evaluation. This gives a Log-normal distribution, see appendix C. The O&M cost is classified into fixed and variable costs expressed in £/kW/year and £/kW/h respectively. They are both taken as percentage of the fuel cost at full load and their distributions are represented using a triangular distribution.

3.5.2 Economic Appraisal

Today different economic techniques are used for evaluating the financial investment in the power industry depending on the purpose of the project evaluation and economic appreciation. Typical operating parameter and techniques that can facilitate decision-making in the power industry investigated in this study are:

- Cost of electricity (CoE)
- Net present-value (NPV)
- Internal rate-of-return (IRR)
- Pay-back period (PBP)
- Cash flow return on investment (CFROI)

The explanation of these techniques as considered for financial investment of employing gas turbine for onsite associated gas utilization for electricity generation are discussed below.

Cost of Electricity

The CoE is used widely as an important parameter for selection of design option for a power plant and for cost comparison of power generation from different technologies. There are different approach adapted in calculating CoE across power industries and energy regulatory authorities. In this study, the total revenue requirement method is used through:

- Estimation of capital investment;
- Estimation of fuel and power plant performance parameter;
- Determination of the economic, financial, and market input parameters;
- Calculation of the total revenue requirement; and
- Calculation of the levelized CoE.

The component of the electricity generation cost is grouped to give CoE in £/kWh equation *3-5* and a generic revenue requirement cost components is described in Table 3-21.

Table 3-21: Component of Total Production Cost

<table>
<tr><td>Capital Recovery (Depreciation)</td><td>Return on Equity</td><td>Return on Debt</td><td>Income Taxes</td><td>Other Insurances</td><td>Fuel Costs</td><td>Operation and Maintenance Cost</td></tr>
<tr><td></td><td colspan="2">Minimum Acceptable Return</td><td colspan="4"></td></tr>
<tr><td colspan="5">Carrying Charges</td><td colspan="2">Expenses</td></tr>
<tr><td colspan="7">Total revenue requirement (Total production cost)</td></tr>
</table>

$$\mathrm{CoE}, £/\mathrm{kWh} = \mathrm{Gen}_{cost} + \mathrm{DP}_{Cost} + IncTax + Em_{Cost} - P_{Cr} \tag{3-5}$$

in which Gen_{cost} is annualised generation cost; DP_{Cost} is depreciation cost; $IncTax$ is income tax; Em_{Cost} is emission cost; P_{Cr} is production tax credit and all the cost are £/kWh.

$$\mathrm{Gen}_{cost} = \left[\left\{\left(\frac{\mathrm{int}(\mathrm{TCI_{spec}})}{1-(1+\mathrm{int})^{-\mathrm{n}}}\right) + (\mathrm{F_{MO}})\right\}\left(\frac{R_u + 1}{8760\mathrm{F_L}}\right) + \mathrm{V_{OM}} + (\mathrm{Fc}\frac{\mathrm{Hr}}{\mathrm{Hv}})\right] \tag{3-6}$$

where $\mathrm{TCI_{spec}}$ is specific overnight total capital investment (TCI), £/kW; int is average loan interest rate used for TCI recovery factor, %; n is economic life of the project, years; $\mathrm{F_{MO}}$ is annual fixed operation and maintenance cost, £/kW/year; R_u is the annual redundant unit (fraction) $\mathrm{F_L}$ is load factor, fraction; $\mathrm{V_{OM}}$ is specific variable operation and maintenance cost, £/kWh; Fc is fuel cost, £/kg; Hr is heat rate, kJ/kWh; and Hv is heating value of fuel, kJ/kg.

$$\mathrm{DP}_{Cost}(\text{£/kWh}) = \frac{\text{spcific plant cost (£/kW)}}{\text{Plant economic life (years)} * 8760\mathrm{F}_{L}} \qquad 3\text{-}7$$

While income tax used is percentage of Gen_{cost} , it is assumed that government will give production tax credit, P_{Cr} for utilising associated gas that will be equal to emission cost Em_{Cost}.

Net present-value (NPV)

A net present-value (NPV) is one of the techniques that can be used to examine the revenue of an investment when the capital cost and the future cash streams can be predicted. NPV of a project is calculated by discounting the future cash-flows using an interest rate and adding the discounted cash-flows up with the initial capital investment cost, see equation *3-8*.

$$\mathrm{NPV} = \sum_{\mathrm{t=1}}^{\mathrm{n}} CF_t\,(1 + intr)^{-t} - I \qquad 3\text{-}8$$

where CF_t is the net cash-flow at the end of the year t; $intr$ is the discount rate; I is the initial cost of the investment.

The implication of the NPV is that the bigger the NVP value the greater the profit and the more attractive the project becomes [113].

Internal rate-of-return (IRR)

The IRR of a project is taken as the value of discount rate that equates the cost for an investment with the subsequent net cash-flow over a number of years that result from the investment [114]. In other words, IRR is the discount rate which produces a zero net present-value that is:

$$\mathrm{IRR} = \mathrm{int}^* \ni' NPV\,(\mathrm{int}^*) = 0 \qquad 3\text{-}9$$

IRR is more like the efficiency of an investment. The implication of the IRR is that acceptable project should have an IRR greater than the required rate-of-return for the project. IRR of a project will give the same confidence as the NPV but when comparing two or more investments, IRR and NPV procedures may not give the same result for acceptance or rejection conclusion, thus other criterion needed to be considered [115].

Pay-back period (PBP)

The pay-back period (PBP) is the time that must elapse for project to recover its investment cost. In other words, is the minimum time n' which satisfies the following equation:

$$\underset{[0,\mathrm{n}]}{min}\{n'\} \ni' \sum_{\mathrm{t=1}}^{n'} CF_t \left(1 + intr\right)^{-t} \geq 0 \qquad \textit{3-10}$$

The implication is that, the shorter PBP the smaller the invested capital is at risk. PBP is regarded as simple pay-back (SPB) when the PBP is computed with zero discount rate (i.e. Zero time value of money), while calculation of PBP using a positive discount rate is recommend and termed discounted pay-back (DPB).

Based on the variant of economic index or accounting method and without promoting one particular accounting method, this study uses net present-value (NPV) and discounted pay-back (DPB) period method. However, occasionally cash flow return on investment valuation method is used to compare annual cash flow during decline regime.

3.6 Coupling Economic and Performance

The analysis of gas turbine for utilization of associated gas is summarised by coupling the technical and economic case within any scenario of gas production schedule and engine unit option, Figure 3-17 below.

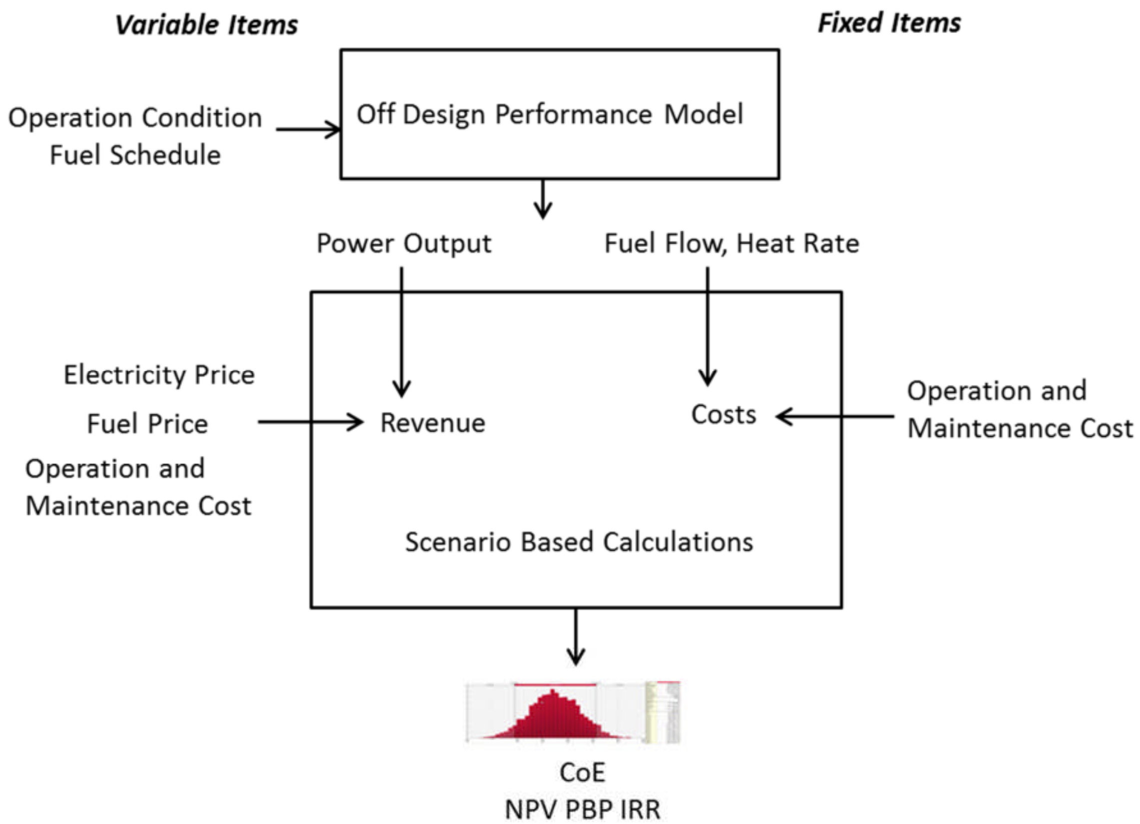


Figure 3-17: Interaction of Major Techno-Economic Parameters

3.6.1 Risk and Uncertainty Model

The uncertain predictions of power plant performance and economic parameters associated with fuel schedule due to gas production decline exacerbates the investment risk facing utilization of APG on gas turbines for power generation and thus the uncertainty of CoE from this process. The risk analysis is employed to answer (qualitatively and quantitatively) the "what-if" scenario questions arising from the uncertainty of the input variables and their likelihood of occurrence.

Basically uncertainty addressed in this study comes from three main sources via the forecasted associated gas from oil production; the gas turbines power plant availability/capacity utilization and underperformance parameter; and finally the capital investment key input parameters to include the TCI cost components and O&M (operations and maintenance) cost assumptions. These can be summed up as listed below:

- Capacity factor
- Production and decline rate
- Available reserve size
- Thermal efficiency
- Forecasted ambient temperature profile
- Availability
- Total capital investment (TCI)
- Fixed/Variable O&M cost and O&M cost escalation
- Depreciate rate
- Discount rate
- Wellhead gas price and makeup-fuel cost and their escalation factor
- Interest rate used for capital recovery
- Average gas turbine engine degradation during operation
- Inflation rate

3.6.2 Sensitivity Analysis

The impact of the input parameters listed above to the total CoE is ascertained. However, is worthwhile to note that the initial source of risk for investigation in this study is from:

1. The associated gas composition,
2. Recoverable quantity of this gas and
3. Its production schedule.

The effect of the gas composition or species reduces the performance of the gas turbine engine compare to the frequently used natural gas as revealed by the performance results of the eight (8) different engine units selected for this study.

The recoverable quantity poses such improbable challenge making it difficult to know the probability that a certain volume of this gas would be produced. This is normally expressed using percentage (i.e. P90, P50, or P10), and is of primary concern when considering the initial power capacity and size of investment and utilization technology options in general.

The production schedule on the other hand causes variation of produced/output power and introduces redundant unit(s) from the initial power capacity as well as underperformance of the gas turbine engine units.

3.6.3 Probabilistic Analysis and Monte Carlo Simulation

Compare to conventional deterministic approach, probability distribution is much more realistic way of describing uncertainties in variables for a risk analysis. The most sensitive variables as revealed by sensitivity analysis result are the focus of the probabilistic analysis. The first element of the probabilistic approach is building of the probability distributions of the highly sensitive input variables to replace the single point values used during deterministic evaluation.

Construction of these distributions is achieved by curve fitting explained in the earlier section when historical data are available and using distributions obtained in literature and reasonable judgment in the absent of historical data. The steps below provides guide on what needed to be considered while constructing probability distribution from historic data.

1. Update the historical variable to current value (using gas wellhead cost as an example) the steps can be followed as: update the wellhead cost to current currency value using cost index equation below

$$\text{Price at reference } year = \text{original price} \times \left(\frac{\text{price index at reference year}}{\text{price index during the original price}}\right) \quad \textbf{(3-11)}$$

2. Construct distribution using the updated cost via curve fitting,
3. Chose a baseline which will be the mean value depending on the distribution,
4. Add a reasonable premium on the cost if necessary to represent the worst cost scenario or future cost increase,
5. Adjust and finish the probability distribution using information from (3) and (4) above.

In general analyses which deals with future predictions in real-world somehow involves element of uncertainty and are too complex to solve by a strict analytical method [116]. The Monte Carlo simulation (MCS) method is used to obtain the desired economic index output probability distribution and cumulative probability.

The MSC method is a sampling experiment whose purpose is to estimate the probability distribution of the key performance outcome variable that depends on numerous probabilistic input variables. It generates a large number of random numbers of the input variables (high sensitive variable probability distributions) and a corresponding value of CoE, or NPV or IRR and the probability distribution by counting the number of times each value of these performance indexes occur. Then the result of the calculations is sorted and plotted in probability distribution and cumulative probability format. It is a reliable way of performing quantitative risk analysis. MSC in this study is performed using commercial software [112].

Chapter 4

Baseline Gas Turbines Associated Gas Utilization

4.1 Associated Gas Capacity Consideration

The flared associated gas capacity for GT utilization evaluated in this case studies is in the range of 10 billion cubic feet (Bcf) to 1 trillion cubic feet (Tcf) ultimately recoverable reserves (URR). This study examines the techno-economic performance of onsite combustion turbine power plant for monetization of associated gas reserves within this volume.

This range of reserve size is considered to represent marginal or small gas resource being flared during most oil production. Is worth mentioning that there is no clear demarcation in judging a reserve size [117], to be marginal but in general this sort of reserve size has been considered as small gas reserves [9]. Associated gas for this case study is a typical Nigerian associated gas composition; see Appendix B for composition of natural gas in this study.

In order to account for the impact of URR size on GT utilization of associated gas evaluation, three distinct URR arrangements is studied. The 10 Bcf -1 Tcf reserve range is grouped into three different reserves for GT utilization scenarios for evaluation via:

(i) **<u>Secenario-1:</u>** Having URR or reserves volume around 1 Tcf and GT utilization initial power plant capacity of about 1006.8 MWe.

(ii) **<u>Secnario-2:</u>** Having URR or reserves volume around 450 Bcf and GT utilization initial power plant capacity of about 450.6 MWe.

(iii) **<u>Secenario-3:</u>** Having associated gas URR or reserves volume of around 17 Bcf and GT utilization initial power plant capacity of about 15.9 MWe.

In all these scenarios a constant annual production decline rate is assumed and other applicable specific conditions and assumptions are listed for a particular scenario.

4.2 Scenario-1 Evaluation

4.2.1 Associated Gas Production Schedule

The first scenario representing 1 Tcf reserves or ultimately recoverable reserves have a production profile with the following assumptions:

- 25 years continuous production duration
- constant annual production decline rate
- associated gas production decline assumes harmonic decline curve
- decline rate is within 6-16%

Starting with an initial annual production of 81.0 Bcf, the production profile for this scenario is shown with 6%, 12% and 16% decline rates in Figure 4-1. The uncertainty in production schedule within 6 to 16 % decline production rates is captured as shown in Figure 4-2 below using Monte Carlo simulation (MCS) method. The MSC used a normal distribution for decline rate distribution and URR distribution output comes out as a lognormal distribution. The estimated reserves production in terms of P10, P50, and P94 are approximately 553 Bcf, 713 Bcf and 1.1 Tcf respectively.

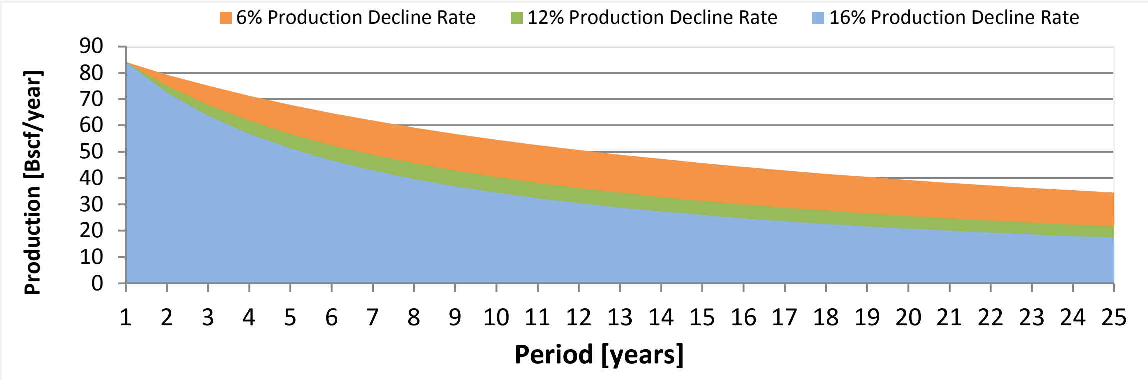


Figure 4-1: Scenario-1 APG Production History for Different Decline Rate

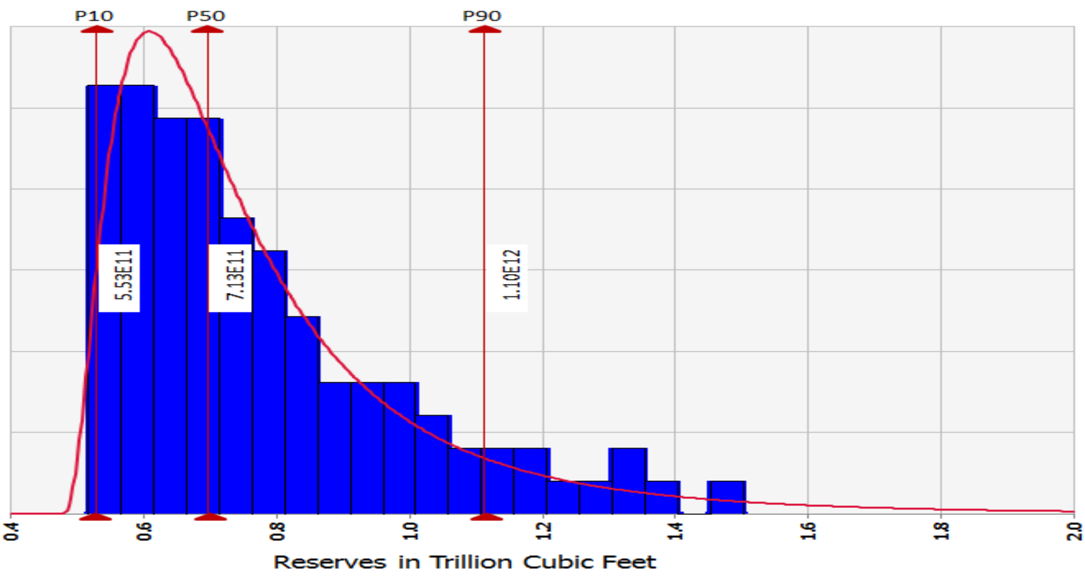


Figure 4-2: Scenario-1 URR Probabilistic Reserves

4.2.2 Engine Unit Selection

The engine fleet in senario-1 comprises of six sets of different gas turbine units with some of the engines in multiple units. In total there are13 GT engine units selected from the engine module library. This is based on the initial gas production of 81.0 Bcf/year. The power plant capacity is found to about 1006.8 MW. Table 4-1 below shows the mix of engine units, their power capacities, fuel consumption and thermal efficiency of each engine units. Arrangements and numbers of particular engine size were predetermined to enable divestment strategy simulations. This was technically evaluated in line with production decline profile to suite redundant engine unit and their withdrawal/divestment timing.

Table 4-1: Engine Units Mix for Scenario-1

Power [MW]	202.4	98.1	85.0	50.5	30.2	27.2	11.2	5.3
Thermal Efficiency [%]	38.0	45.0	32.6	38.3	39.5	36.4	31.4	31.0
Number of Unit Used	x2	x3	x1	x1	x3	x3	x0	x0
Fuel Flow per unit [kg/s]	11.71	4.74	5.71	2.85	1.68	1.64	0.79	0.35

The baseload effective/design point total fuel flow of the fleet is 58.15 kg/s (81 Bcf/year), and baseload output power of 1006.8 MW, see equation (4-1) and Table 4-1 for calculation of both values. The baseload effective design point thermal efficiency of this scenario fleet selection is found to be 38.0%, using equation (4-2) and figures from Table 4-1. Conditions for the GT units for power plant include design point ISA conditions, and fuel heating value of 45.6158 MJ/kg (45616 kJ/kg) see Appendix B.

$$\text{Baselod Fuel Flow or Power} = \sum_{i=1}^{n} \text{NFi} \tag{4-1}$$

Where n is number of engine unit; N, design point power of fuel flow or power capacity; and Fi is the number of each engine unit.

$$\text{Effective } \eta_{\text{thermal}}(\%) = \frac{\text{Power (kW)}}{\text{Fuel flow (kg/s)} * \text{Fuel heating value (kJ/kg)}} \tag{4-2}$$

4.2.3 Engine Capital Cost Estimation

The total specific purchased equipment cost is the sum of the total costs of all the 13 engine units divided by the sum of the engine total output power. Total specific PEC for this scenario is calculated to be 204.13 £$_{2010}$/kW, see specific PEC estimation procedure in chapter 3.

Table 4-2: The Scenario-1 TCI Cost Variables

<table>
<tr><td colspan="3">Total Capital Invest Component</td><td colspan="3">Range of TCI Values (£/kW)</td></tr>
<tr><td rowspan="12">I. Fixed capital investment (FCI)</td><td rowspan="9">(A). Direct Cost, DC</td><td>1. Onsite Cost (ONSC)</td><td>Lower value</td><td>Deterministic value</td><td>Upper value</td></tr>
<tr><td>* Purchased equipment cost (PEC)</td><td>150.00</td><td>204.13</td><td>300.3</td></tr>
<tr><td>* Purchased equipment installation</td><td>30.00</td><td>102.06</td><td>270.27</td></tr>
<tr><td>* Piping</td><td>15.00</td><td>51.03</td><td>210.21</td></tr>
<tr><td>* Electrical equipment & materials</td><td>15.00</td><td>24.50</td><td>45.06</td></tr>
<tr><td>2. Offsite costs (OFSC)</td><td></td><td></td><td></td></tr>
<tr><td>Land</td><td>0.00</td><td>18.37</td><td>30.03</td></tr>
<tr><td>Civil, structural & architectural work</td><td>22.50</td><td>61.24</td><td>270.27</td></tr>
<tr><td>Service facilities</td><td>45.00</td><td>30.62</td><td>300.3</td></tr>
<tr><td rowspan="3">(B). Indirect Cost</td><td>1. Engineering & supervision</td><td rowspan="3">37.50</td><td rowspan="3">61.24</td><td rowspan="3">225.23</td></tr>
<tr><td>2. Construction cost</td></tr>
<tr><td>3. Contingencies</td></tr>
<tr><td colspan="2">II. Other Outlays</td><td>A. Start-up cost
B. Working capital
C. cost of licencing, R&D
D. Allowance for fund used during Construction (AFUDC)</td><td>75.00</td><td>51.03</td><td>45.6</td></tr>
<tr><td colspan="3">Specific TCI COST</td><td>390.00</td><td>604.22</td><td>1711.71</td></tr>
</table>

The specific total capital investment cost value as calculated from the table above is used to produce a triangular distribution (Figure 4-3) for specific TCI employed during probabilistic analysis. The 390 £/kW is used as the minimum value, 604.22 £/kW which represent the deterministic value is used as most likely value and finally the 1711.71 £/kW is used as the maximum value.

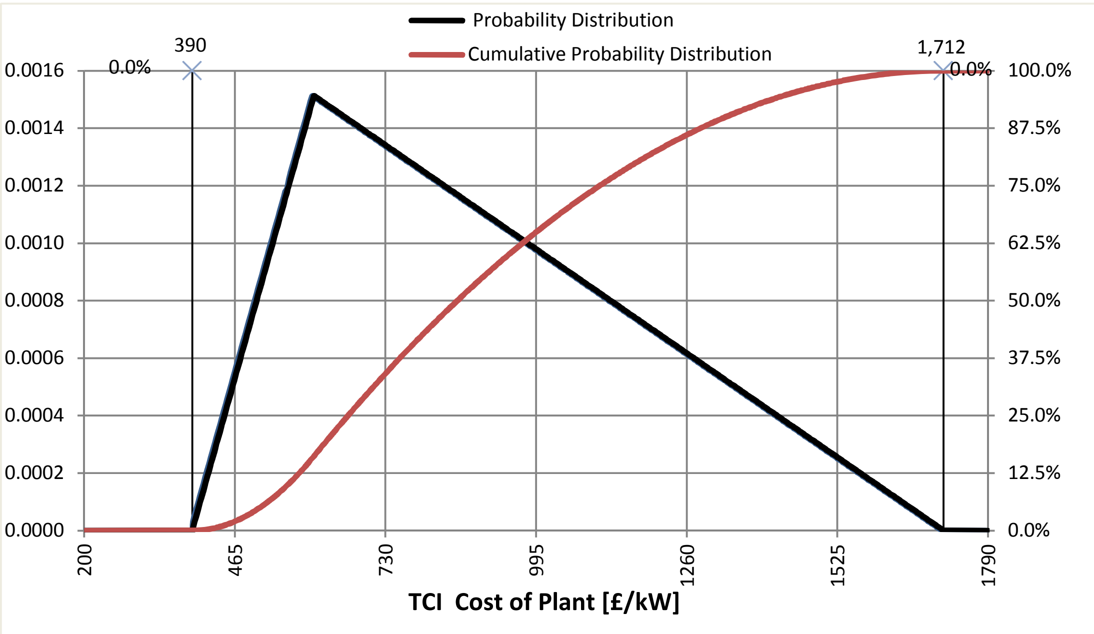


Figure 4-3: TCI Cost Probability Density Distribution

4.2.4 Techno-Economic Analysis

Table 4-3: Summary of Techno-Economic Parameters and Assumptions

Parameter	**Value**
Nominal plant capacity (kW)	1006800
Thermal efficiency (%)	39.2
Fuel heating value (kJ/kg)	45600
Site ambient temperature (K)	288.15
Associated gas URR (Tcf)	1
Initial gas production (Bcf/year)	81.0
Capacity factor (hour/year)	7623
Associated gas decline rate (%)	11
Plant specific total capital cost (£$_{2010}$/kW)	604.22
Associated gas production cost (£$_{2010}$/kg)	0.09
Fixed O&M cost (£$_{2010}$/kW/year)	4.5
Variable O&M cost (£$_{2010}$/kWh)	0.00191
Monetization duration (years)	25
Interest rate for TCI recovery (%)	10
Depreciation cost (£$_{2010}$/kWh)	0.00354
Electricity price £$_{2010}$/kWh	0.095
Emission tax = Flare reduction credit (%)	0
Revenue tax (%)	25
Discount rate (%)	15
O&M costs escalation (%)	2
Electricity price and gas escalation (%)	1

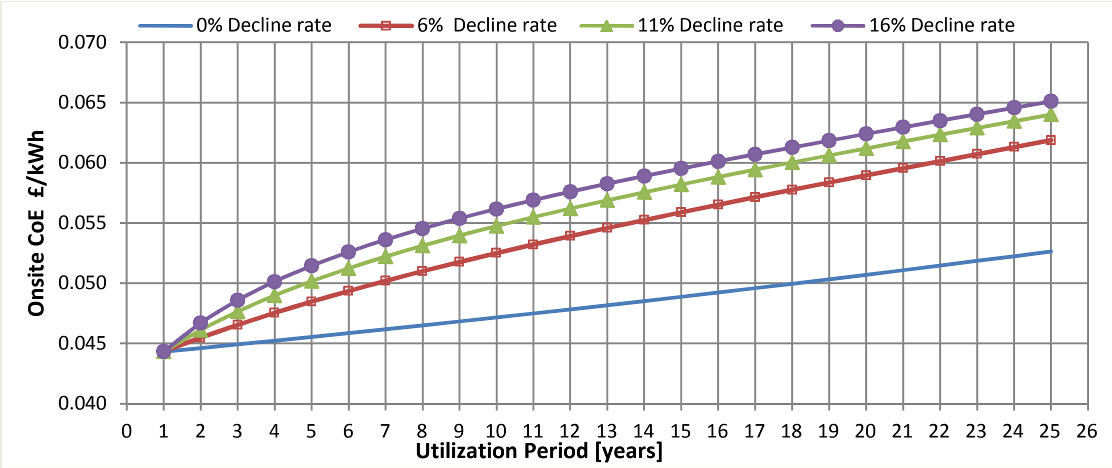


Figure 4-4: The Impact of Decline Rate on the Onsite Cost of Electricity (CoE)

The change in CoE due to decline is analysed by comparing three different decline rates with a non-decline or zero decline rate situation, Figure 4-4. There is a general increase in CoE observed across the options (with or without decline) contributed by such factors to include: generation cost escalation factor, engine degradation (depreciation cost), etc. as would be expected.

However, there is a substantial increase in onsite CoE as decline rate increases over the utilization period. For instance, an increase in CoE when there is no production decline (or a zero decline) is 20% at the end of 25 years monetization period. Whereas for the same period, CoE increases to 41%, 45% and 48% for 6%, 11% and 16% associate gas production decline rate respectively.

The increase in cost of electricity associated with increase in production decline can be simply attributed to the fact that the initial baseload power capacity is constantly declining Figure 4-5 below as less fuel becomes available. This power capacity depletion contributed by production decline reduce power plant effective thermal efficiency, as well as net capacity factor and upset the economic performance of the plant as it shoots electricity production cost high.

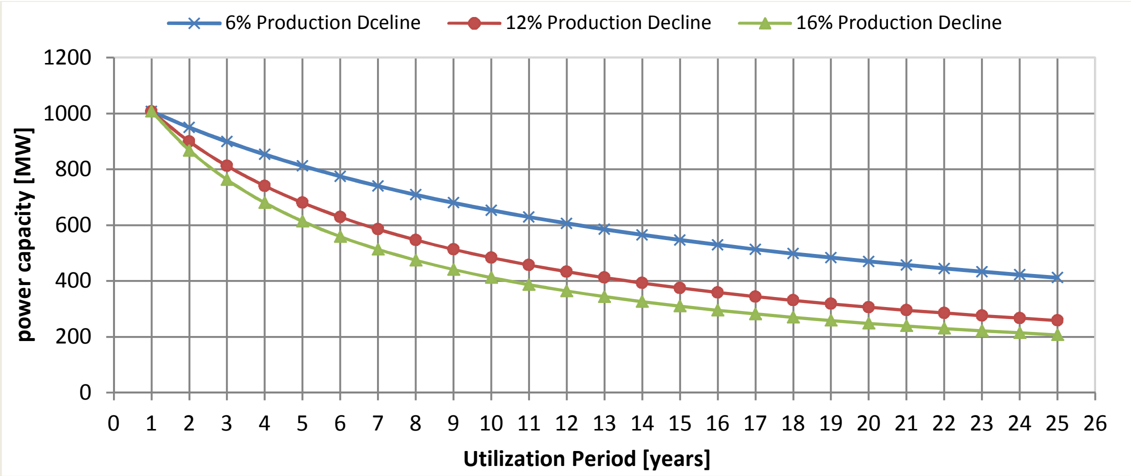


Figure 4-5: Power Plant Capacity Reduction due to Decline

Following the anticipated increase in CoE due to increasing production decline rates, the impact of high electricity production cost is analysed. The results for the criteria selected for evaluation are shown in Figure 4-6 and Figure 4-7 below. The economic performance assed based on a 11% associated gas production decline rate, Figure 4-4 above shows that CoE at some point in time during utilization period could go as high as 0.065 £/kWh. Whereas the selling price of electricity at that value will only give IRR of 3% approximately, NPV of about £89.4 million (Figure 4-6 below) and PBT of about 9.8 years (Figure 4-7 below). In other words the selling price of electricity with production decline rate of about 16% should be well above £0.65/kWh for a fair economic justification given other conditions as stated for this evaluation listed in Table 4-3 above.

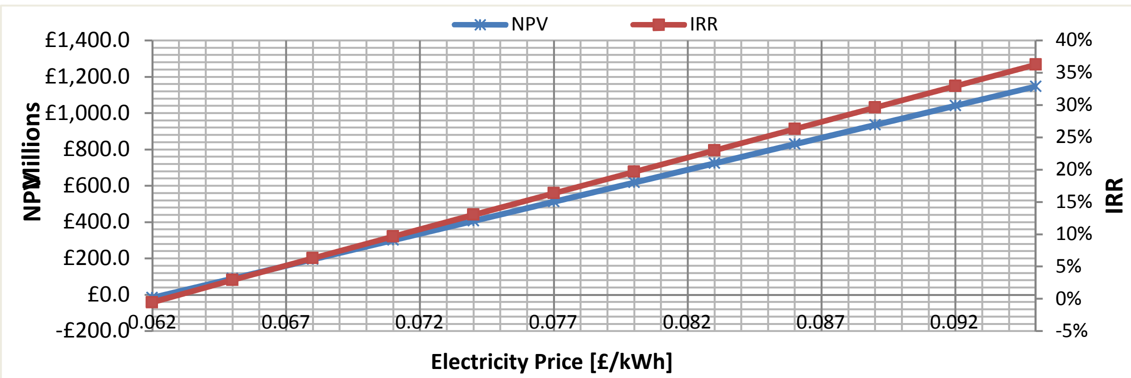


Figure 4-6: Change in NPV and IRR with Electricity Price

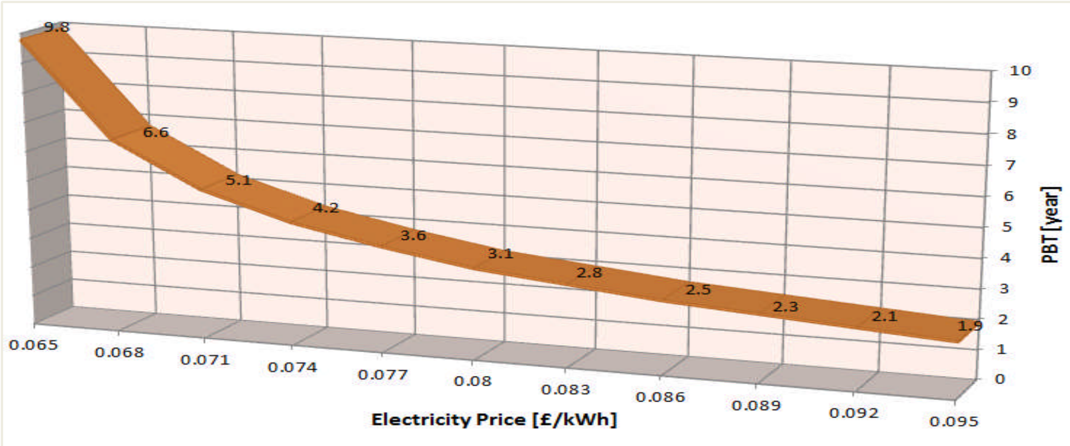


Figure 4-7: Change in PBT with Electricity Price

Cost of fuel is another important element of CoE for gas-fired power generation plant. Generally associated gas cost can be regarded to be minimal when its processing cost is less and its production processes is not affecting oil production. To assign a cost to associated gas and to evaluate same, two extreme conditions were considered.

Thus, the cost of this gas can be regarded as zero in one instance, since it could have been otherwise wasted to flaring and even incurring penalties in some cases during oil production. In that sense it cost nothing, except the gathering processing and storage cost. Again, when this gas requires processing the cost of this gas can increase unexpectedly depending on their nature and remoteness of the field. Based on these two instances, associated gas cost was evaluated against the three criteria Figure 4-8 and Figure 4-9 below.

Ultimately the cost of associated gas can increase or reduce the internal rate of return (IRR) the net present value (NPV) and pay-back time (PBT) of GT associated gas utilization setup as evaluated. Increase associated gas cost is reduces NPV and IRR, with both values as native when associated gas cost is between 0.20 - 0.22 £/kg, Figure 4-8. Likewise, the impact of associated gas cost on PBT within the 0-22£/kg cost shows a fair increase in PTB until gas cost reaches 0.14 £/kg when the PBT rapidly increases before going to non PBT under the monetization duration of 25 years being considered, Figure 4-9 below.

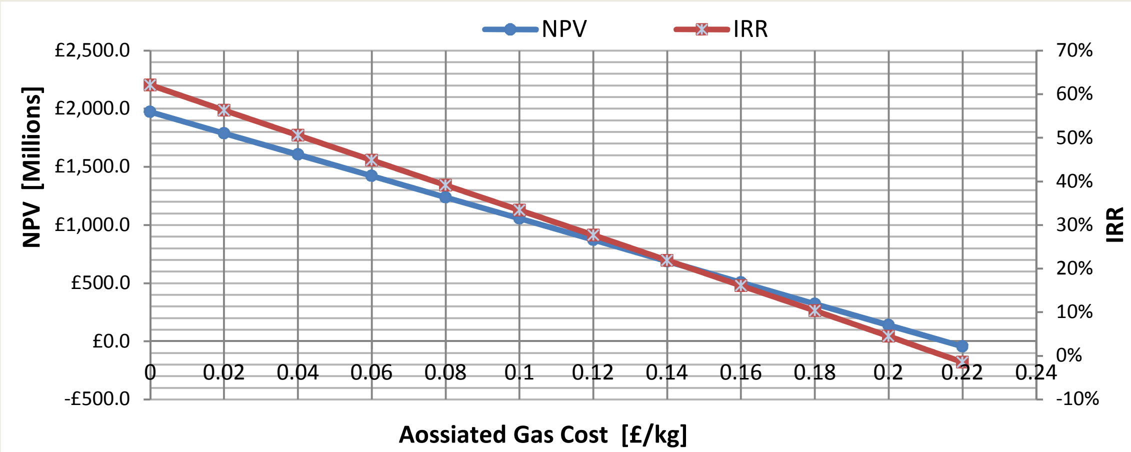


Figure 4-8: Impact of Associated Gas Production Cost on NVP and IRR

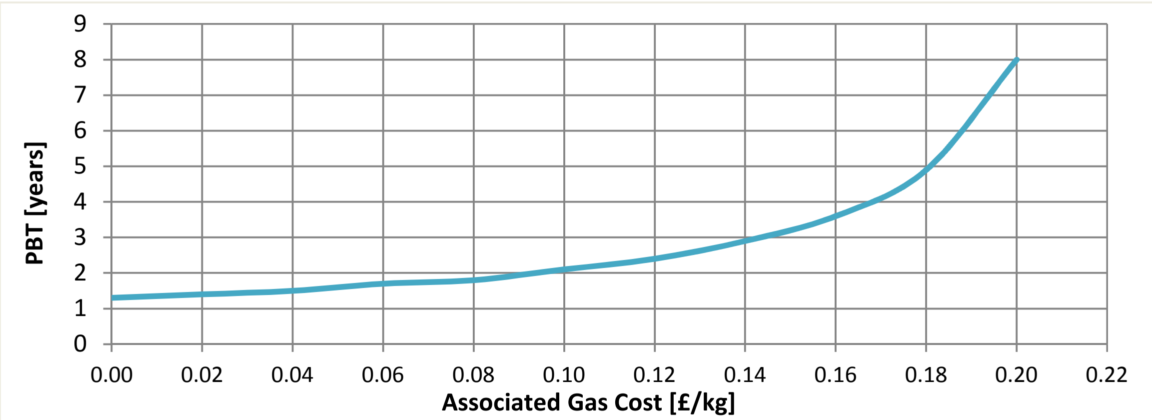


Figure 4-9: Change in Associated Gas production Cost and PBT

4.2.5 Uncertainty and Risk Analysis – Probabilistic Approach

The parameters used for the calculation of CoE and assessment of investment options are characterized by uncertainties since some of them are unknown coupled with the fact they are subject to change within the 25 years of project duration. Thus, there is need to account for these changes and uncertainties quantitatively in CoE estimation and the overall project economic analysis to project likelihood of their occurrence and what happens afterwards should they occur. The Monte Carlo simulation method is used for this probabilistic study. This computational mathematical technique enabled project variable parameters in this model to be represented using distributions and the computation runs 10000 iterations producing CoE, NPV and IRR such that the probability of each of economic index values within certain range as may be desired for investment decision is ascertained. The distribution for the risk variables are defined in Table 4-4 below.

Table 4-4: Probability Distributions for the Risk Variables

Risk variables	Deterministic value	Distribution	Distribution details	
			Lower bound	Upper bound
Decline rate (%)	0.11	Normal	5% (0.06)	95% (0.16)
APG wellhead cost (£/kg)	0.09	Triangular	0.0	0.20
Redundant power (fraction)*	0.0	Triangular	0.0	0.75
Fuel heating value (kJ/kWh)	45616	Uniform	41040	47616
Plant TCI cost (£/kW)	604.22	Triangular	390.00	1711.71
Interest rate for TCI recovery (%)	0.1	Normal	5% (0.06)	95% (0.12)
Capacity factor (hour/year)	7821	Normal	5% (7446)	95% (7796)
Fixed O&M cost (£/kW/year)	5.0	Triangular	3.0	10.0
Variable O&M cost (£/kWh)	0.001913	Triangular	0.00183	0.010
Revenue tax (%)	0.25	Normal	5% (0.15),	95% (0.40)
Discount rate (%)	0.1	Triangular	0.08	0.15
Electricity price (£/kWh)	0.095	Uniform	0.065	0.1
Depreciation cost (£/kWh)	0.0032	Uniform	0.0023	0.0034

* Redundant unit is fraction of the plant capacity

Sensitivity Analysyis of Parameters to CoE

Cost of generated electricity is generally one of the major parameter for assessing the viability of power-generation technology and for comparing power technology options. This has several techno-economic variables associated with it that can change periodically. Particularly in this study, production decline rate has been identified to change most of these variables. Thus, the variables influencing the cost of electricity for GTW monetization considered in this scenario and their ranking based on correlation coefficient to CoE for probabilistic method are shown in Figure 4-10 below. The parameter with most sensitivity, (that is more influential) to the CoE has the highest value. This understanding generally identifies critical input variables pointing out where to spend extra resources in data collection and improving data estimates [118].

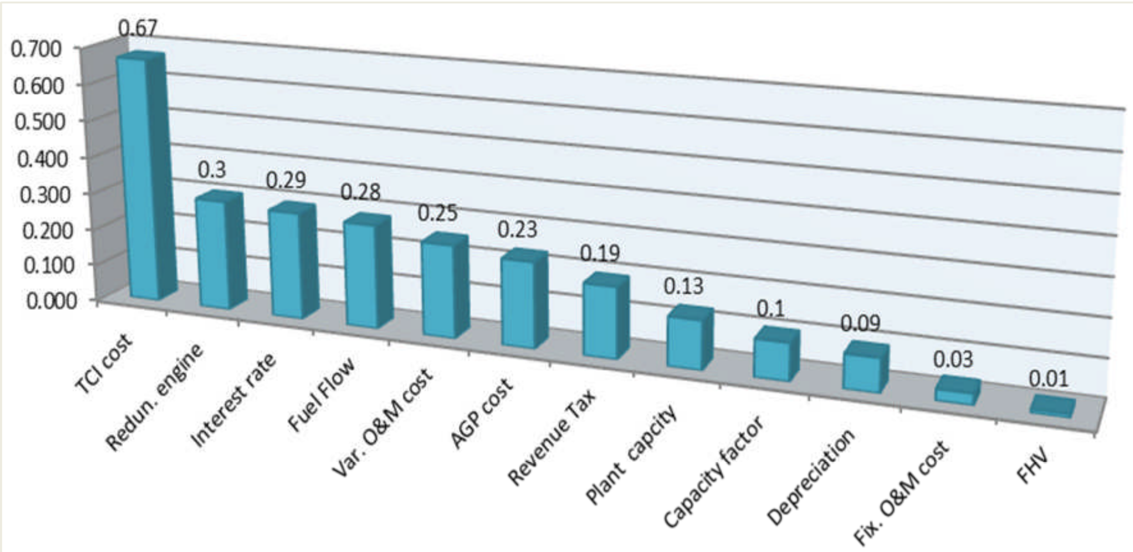


Figure 4-10: CoE Input Parameter Correlation Coefficient

The most sensitive variable, the specific total capital investment (TCI) cost in no doubt should have the highest rank since it represent the utmost bulk capital disbursement. The most interesting discovery is the second variable (redundant engine units). The position of redundant power (engine unit) further demonstrates the implication of decline on CoE and stress the need for an approach to mitigate redundant gas turbine engine units. The interest rate used for capital recovery (the third ranked variable) stresses the need to evaluate the financing option (i.e. fashioning proportion of debt and equity). The fourth ranked variable is the fuel flow which is linked to both the capacity factor as well as decline and can points to the power setting monitoring. All these variables as shown in Figure 4-10 have significant effect on the CoE. Apparently, is quite interesting to see that fuel heating value (FHV) has the least effect among the variables. Comparing the heating value of associated gas species within this study with the normal natural gas heating value, there will be a less significant change in economic performance between the two gases; giving the two fuel heating values are quite close. Also the change in CoE from selected input variables shows specific TCI cost fluctuates considerably among others variables being considered in Figure 4-11. Considering the range of variable distributions, the most stable random values come within P45 to P65 of the values.

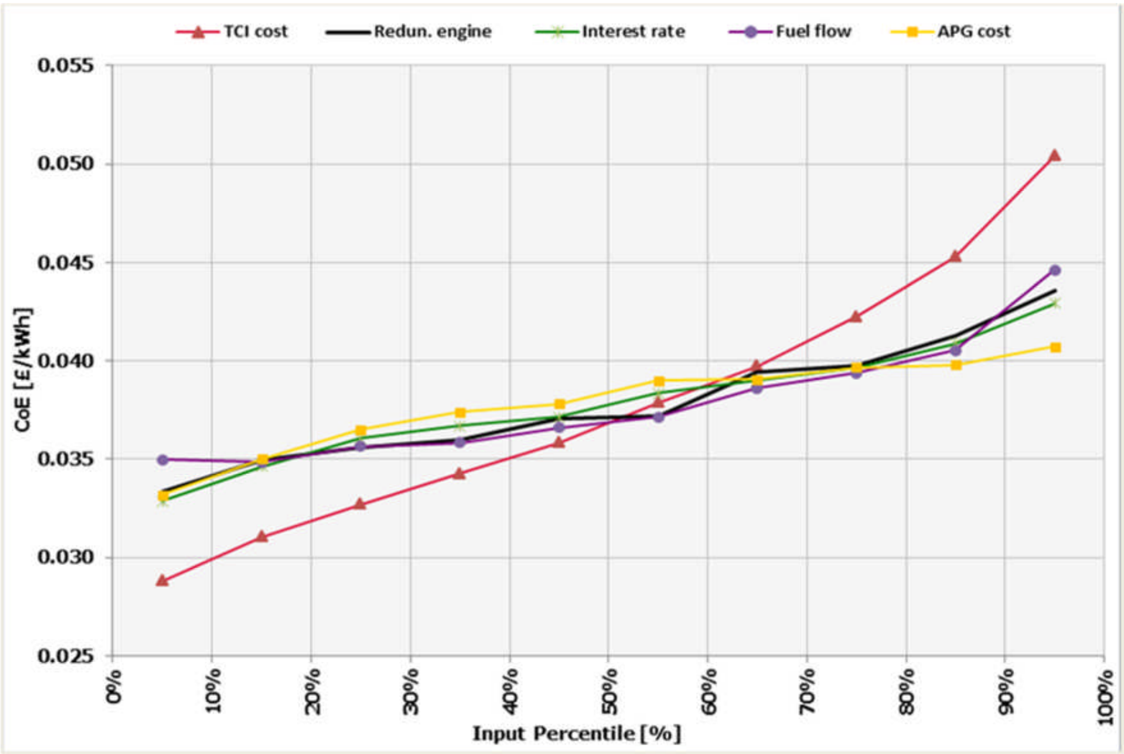
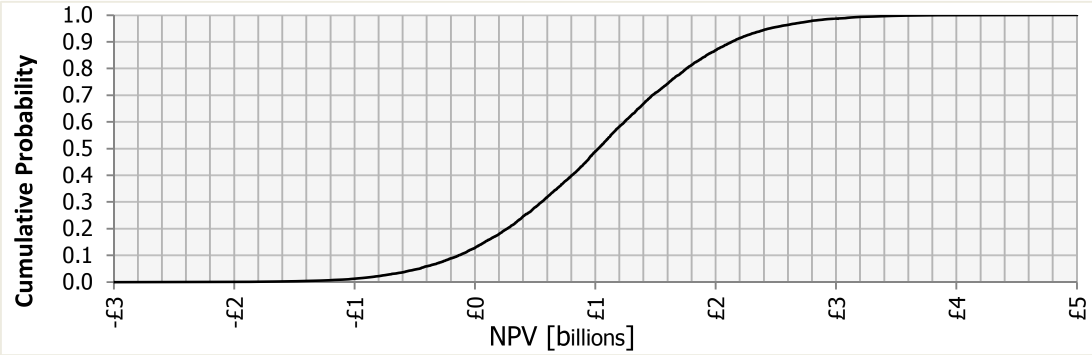
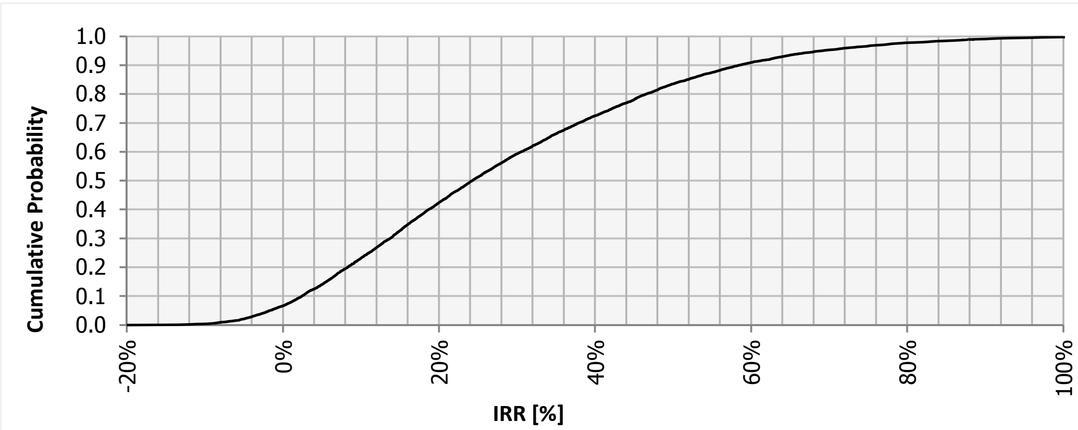


Figure 4-11: Change in CoE across Range of Selected Inputs Values

The Probabilistic Predictions for NPV and IRR



(a)



(b)

Figure 4-12: (a) NPV and (b) IRR Predictions for Scenario-1 Based on the Total Effect of the Risk Variables

Predicting economic performance parameters (say NPV, IRR etc.) given the total effect of risk variables considered in this scenario using probability approach reveal more detailed information. The desired range of economic performances in this project can be quantified using probability of the economic performance yield. For instance, the economic performance yield using expected NPV value of more than £ 1.75 billion is 20.2% (i.e. 79.8% that NPV will be under £1.75 billion) as marked in Figure 4-13 below. Alternatively certain NPV range could be given and their probability of occurring deduced. This scenario have 99.8% of the NPV between -1.65 to 4.10 (£ billion). This knowledge can be extended to any range of economic performance index as desired. The uncertainty in NPV as predicted above, shows that considerable amount is associated with variation in production schedule due to decline as explained in next section.

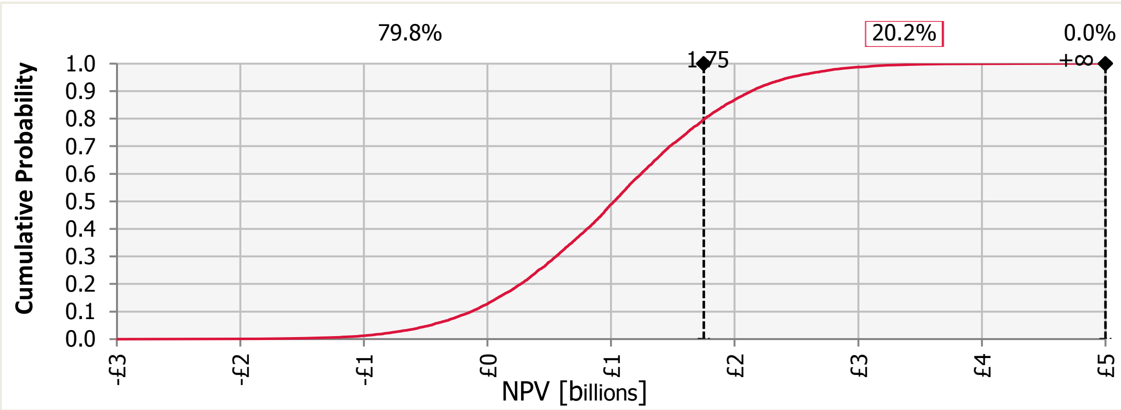


Figure 4-13: Determination of Probability for NPV Value of £1.75 Billion

<u>The Probabilistic Predictions of NPV and IRR in terms of URR</u>

The predictions of NPV and IRR in terms of the associated gas URR which is a function of initial production rate and decline rate is possible as shown in Figure 4-14 and Figure 4-15 below. Both figures show that probability of IRR and NPV increases as probability or degree of confidence of associated gas URR increase. Considering a typical associated gas URR of about 1 Tcf (or P50), the IRR will be approximately 25% having a probability of 0.5 (or half). Thus, the probability of producing a certain associated gas URR and the internal rate of return on investment associated to that URR can be predicted.

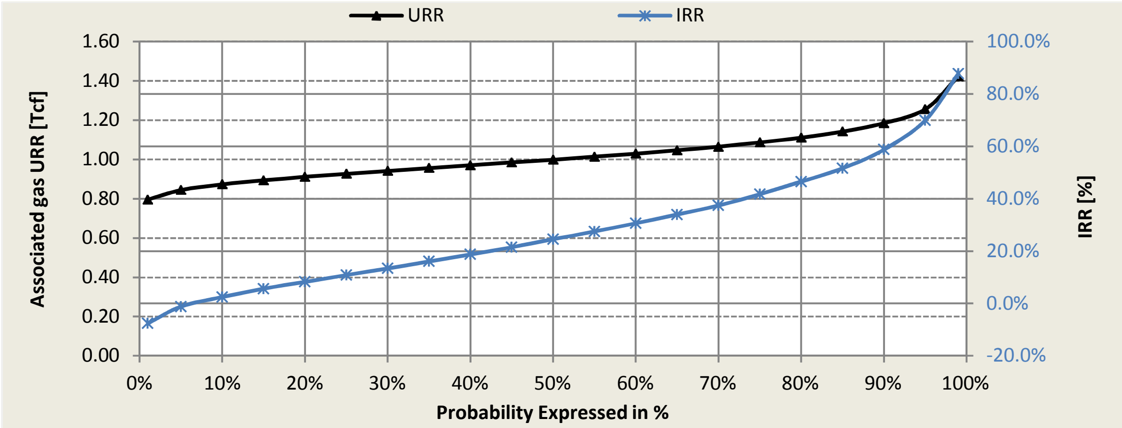


Figure 4-14: Change in IRR and Associated Gas URR using Percentile

As explained in in Figure 4-15, the NPV can be predicted in similar manner for a given URR or range of URR just like the IRR. Perhaps, both pair of NPV and IRR can be obtained for URR or range of URR and for a desired IRR and NPV a corresponding associated gas URR can be predicted. For associated gas URR less than P10 IRR is less than 1% with a probability of 0.1 and the NPV is less than £ 0.149 billion with a probability of 0.1 Conceivably this can be extended to demonstrates how decline degrades economic performance, since increasing URR is associated with a decrease in production decline rates.

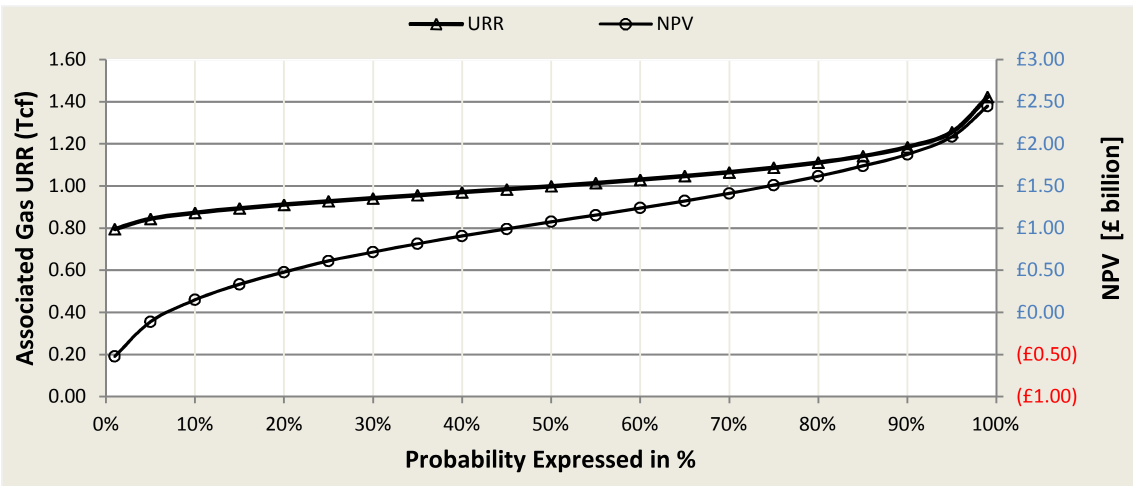


Figure 4-15: Change in NPV Associated gas URR using Percentile

4.3 Scenario-2 Evaluation

4.3.1 Associated Gas Production Schedule

The second scenario is about 480 Bcf reserves or ultimately recoverable reserves having a production profile generated with the following assumptions:

- 25 years continuous production duration
- constant annual production decline rate
- associated gas production decline assumes harmonic decline curve
- decline rate within 6-16%
- initial production rate is 36 Bcf/year

The production profile for this scenario based on the assumptions listed above is shown in Figure 4-16 below for 6%, 12% and 16% decline rates. Figure 4-17 below compares impact of production decline on different URR using scenarios 1 and 2. The MCS of the production profile using the above data set produce URR with a lognormal distribution. The URR in terms of P10, P50 and P90 for the production parameters is highlighted in Figure 4-18below.

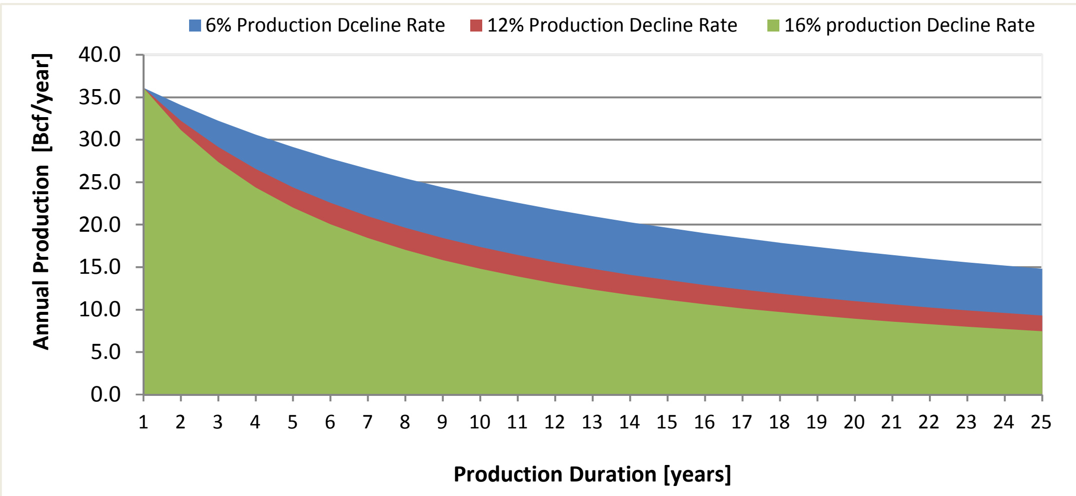


Figure 4-16: Scenario-2 APG Production History for Different Decline Rates

Evidently increasing decline rate has damaging effect on the production schedule but has same impact on both small and big URR based the initial assumptions used in generating production profile. Considering the 25 years utilization during, an increase in production from 6% to 16% lowers both scenarios 1 and 2 URR to half at the last year of utilization period.

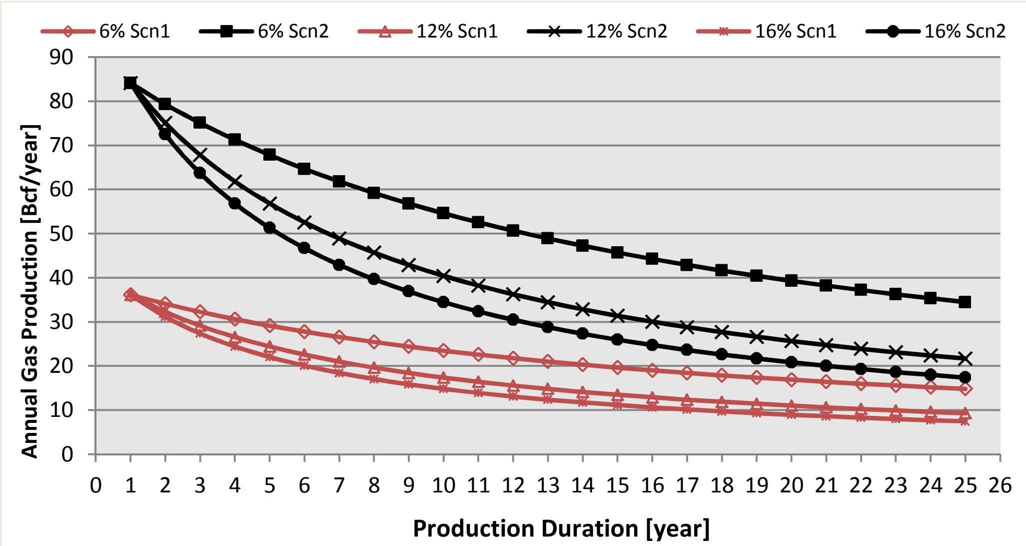


Figure 4-17: Comparing Impact of Production Decline Rate on Different URR Size

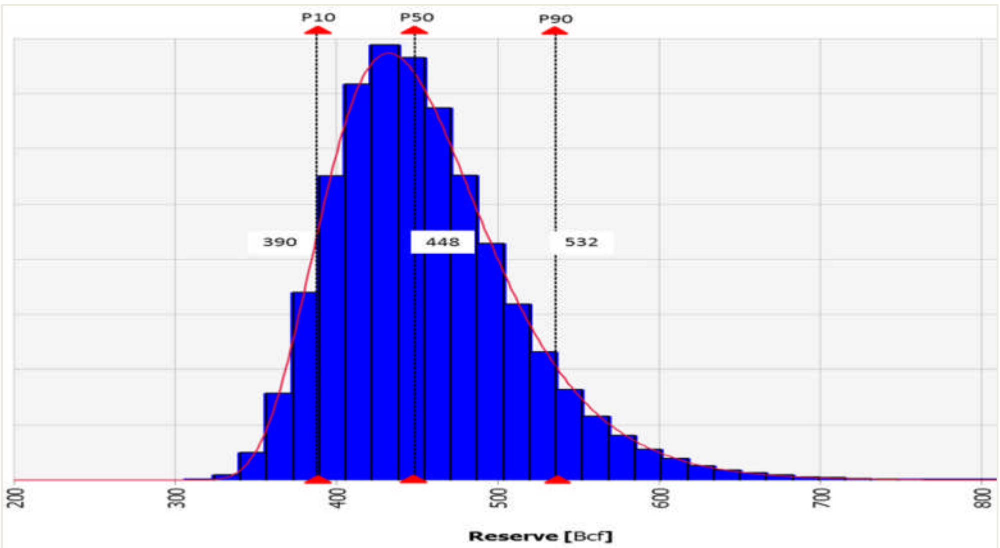


Figure 4-18: Scenario-2 URR Probabilistic Reserves

4.3.2 Engine Unit Selection

The engine fleet in senario-2 comprises of five sets of different gas turbine units with some of the engines in multiple units. In total there are seven GT engine units selected from the engine library. This is based on the initial gas production of 36 Bcf/year. The power plant nominal capacity is found to about 450.6 MW. The mix of engine units, their power capacities, fuel consumption and thermal efficiency of each engine units are shown in Table 4-5 below. The baseload effective/design point total fuel flow of the fleet is 24.35 kg/s (36 Bcf/year). The baseload effective design point thermal efficiency of this scenario fleet selection is found to be 41.0%, using equation (4-2) and figures from Table 4-5 below. Conditions for the GT units for power plant include design point ISA conditions, and fuel heating value of 45.6158 MJ/kg (45616 kJ/kg) see appendix B.

Table 4-5: Engine Units Mix for Scenario-2

Power [MW]	202.4	98.1	85.0	50.5	30.2	27.2	11.2	5.3
Thermal Efficiency [%]	38.0	45.0	32.6	38.3	39.5	36.4	31.4	31.0
Number of Unit Used	x1	x2	x0	x0	x1	x0	x1	x2
Fuel Flow per unit [kg/s]	11.71	4.74	5.71	2.85	1.68	1.64	0.79	0.35

4.3.3 Engine Capital Cost Estimation

The total specific purchased equipment cost is the sum of the total costs of all the seven engine units divided by the sum of the engine total output power. Total specific PEC for this scenario is calculated to be 204.13 (2010 £/kW), see specific PEC estimation procedure in chapter 3. The calculated PEC cost is used to estimate the specific TCI cost of the power plant in Table 4-6 below. The deterministic value from this estimation is 691.49 £/kW, with upper and lower bound values for the specific TCI cost for probability distribution as 1934.01 £/kW and 440.70 £/kW respectively.

Table 4-6: The Scenario-2 TCI Cost Variables

<table>
<tr><th colspan="3">Total Capital Invest Component</th><th colspan="3">Range of TCI Values (£/kW)</th></tr>
<tr><td rowspan="12">I. Fixed capital investment (FCI)</td><td rowspan="9">(A). Direct Cost, DC</td><td>3. Onsite Cost (ONSC)</td><td>Lower value</td><td>Deterministic value</td><td>Upper value</td></tr>
<tr><td>* Purchased equipment cost (PEC)</td><td>169.50</td><td>204.13</td><td>339.30</td></tr>
<tr><td>* Purchased equipment installation</td><td>33.9</td><td>116.81</td><td>305.37</td></tr>
<tr><td>* Piping</td><td>16.95</td><td>58.40</td><td>237.51</td></tr>
<tr><td>* Electrical equipment & materials</td><td>16.95</td><td>28.03</td><td>50.90</td></tr>
<tr><td>4. Offsite costs (OFSC)</td><td></td><td></td><td></td></tr>
<tr><td>Land</td><td>0.00</td><td>21.02</td><td>39.93</td></tr>
<tr><td>Civil, structural & architectural work</td><td>25.42</td><td>70.08</td><td>305.37</td></tr>
<tr><td>Service facilities</td><td>50.85</td><td>35.04</td><td>339.3</td></tr>
<tr><td rowspan="3">(B). Indirect Cost</td><td>1. Engineering & supervision</td><td rowspan="3">42.38</td><td rowspan="3">70.08</td><td rowspan="3">254.48</td></tr>
<tr><td>2. Construction cost</td></tr>
<tr><td>3. Contingencies</td></tr>
<tr><td colspan="2">II. Other Outlays</td><td>A. Start-up cost
B. Working capital
C. cost of licencing, R&D
D. Allowance for fund used during Construction (AFUDC)</td><td>84.75</td><td>58.40</td><td>67.86</td></tr>
<tr><td colspan="3">Specific TCI COST</td><td>440.70</td><td>691.49</td><td>1934.01</td></tr>
</table>

4.3.4 Techno-Economic Analysis

Table 4-7: Summary of Techno-Economic Parameters and Assumptions

Parameter	Deterministic Value
Nominal plant capacity (kW)	450600
Thermal efficiency (%)	41.0
Fuel heating value (kJ/kg)	45616
Site ambient temperature (K)	288.15
Associated gas URR (Bcf)	450
Initial gas production (Bcf/year)	36.0
Capacity factor (hour/year)	7623
Associated gas decline rate (%)	11
Plant specific total capital cost (£$_{2010}$/kW)	691.49
Associated gas production cost (£$_{2010}$/kg)	0.09
Fixed O&M cost (£$_{2010}$/kW/year)	3.5
Variable O&M cost (£$_{2010}$/kWh)	0.00191
Monetization duration (years)	25
Interest rate for TCI recovery (%)	10
Depreciation cost (£$_{2010}$/kWh)	0.00354
Electricity price £$_{2010}$/kWh	0.095
Emission tax = Flare reduction credit (%)	0
Revenue tax (%)	25
Discount rate (%)	15
O&M costs escalation (%)	2
Electricity price and gas escalation (%)	1

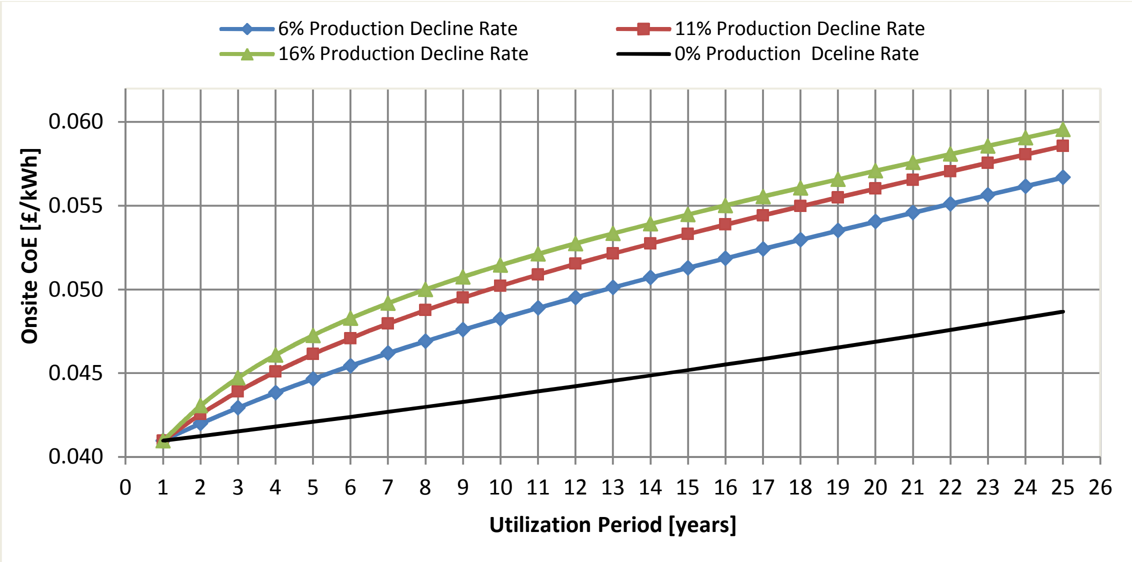
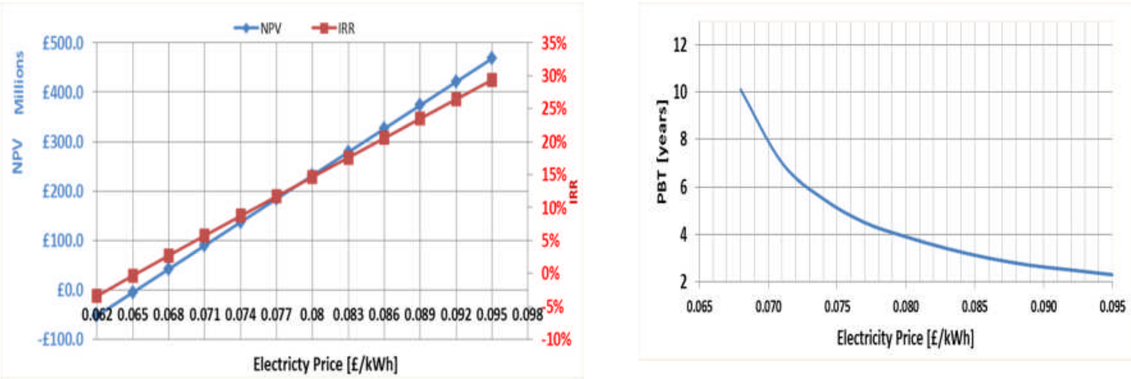


Figure 4-19: The Impact of Decline Rate on the Onsite Cost of Electricity (CoE)

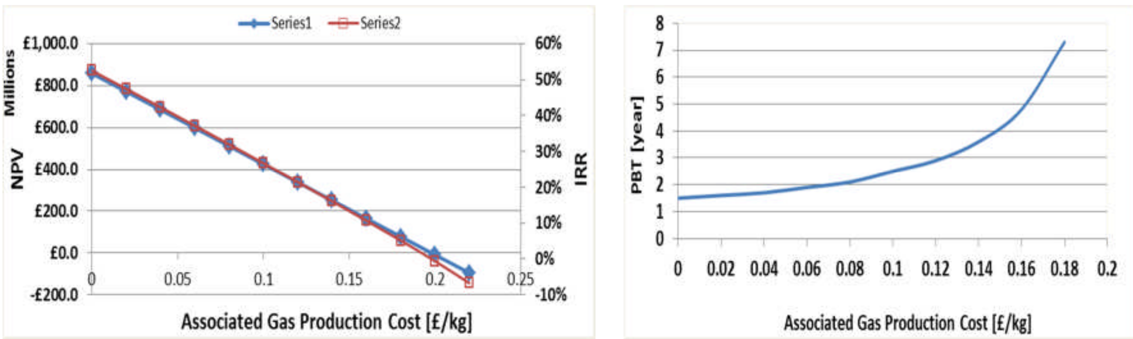
The change in CoE due to decline is analysed by comparing three different decline rates with a non-decline or zero decline rate situation, Figure 4-19 above. There is a general increase in CoE observed across the options including the option zero-decline rate decline. This is contributed by such factors to include: generation cost escalation factor, engine performance degradation (depreciation cost), etc. as would be expected over the life of the power plant.

However, there is a substantial increase in onsite CoE as decline rate increases over the utilization period as witnessed in the scenario-1. For instance, an increase in CoE when there is no production decline (or a zero decline) is 19.5% at the end of 25 years monetization period. Whereas for the same period, CoE increases to 39 %, 43% and 46% for 6%, 11% and 16% associate gas production decline rate respectively. Thus, comparing the impact of production decline rate at the end of project economic life of 25 years for scenario-1 and scenario-2 we have approximately 1%, 1% and 2% increase in CoE for the 6%, 11% and 16% production decline rate respectively.



(a) (b)

Figure 4-20: Change in NPV IRR and PBT with Electricity Selling Price



(a) (b)

Figure 4-21: Impact of Associated Gas Production cost on NVP IRR and PBT

Following the anticipated increase in CoE due to increasing production decline rates, the impact of high electricity production cost is analysed. The results for the criteria selected for evaluation are shown in Figure 4-20 above. The economic performance assed based on a 11% production decline rate, shows that selling price of electricity should be well above £0.065/kWh for a fair economic justification given other conditions as stated for this evaluation in Table 4-7 above. Again from Figure 4-21 above, the cost of associated gas at above 0.18 the NPV becomes negative and IRR will be well beyond 4%. Likewise, the impact of associated gas cost above 0.18£/kg on PBT will move from 7.3 years to a condition where the project will never breakeven throughout the 25 years period of utilization.

4.3.5 Uncertainty and Risk Analysis – Probabilistic Approach

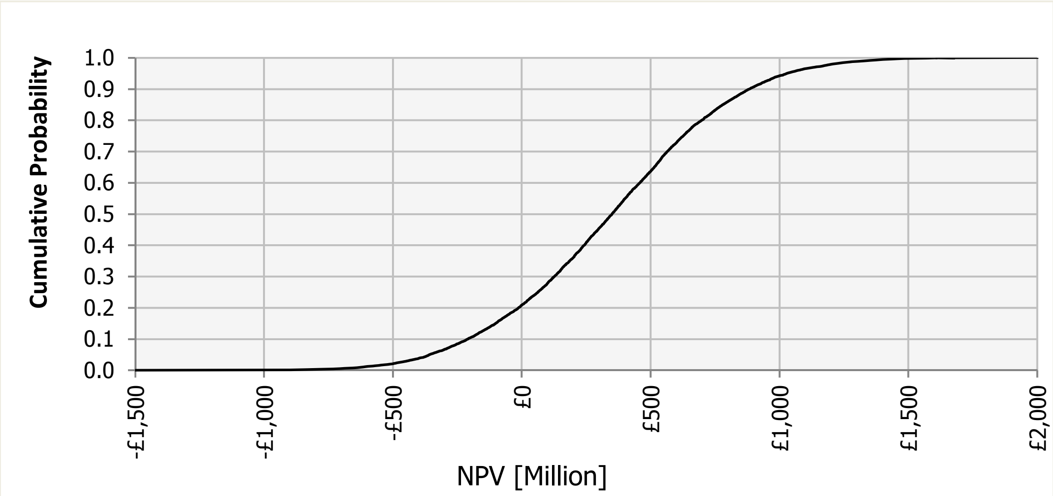
Monte Carlo Simulation with 10000 iterations as before in scenario-1 is conducted with the probabilistic distribution for the risk variables as shown in Table 4-8.

Table 4-8: Probability Distributions for the Risk Variables

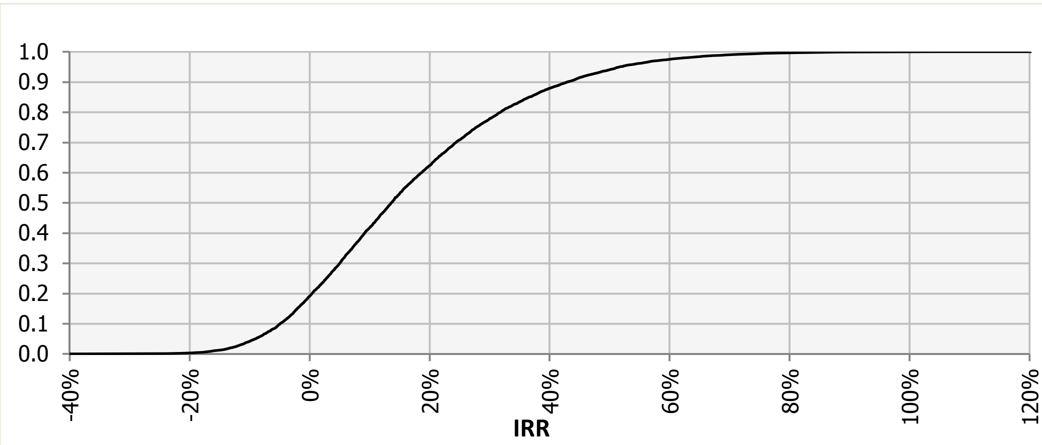
Risk variables	Deterministic value	Distribution	Distribution details	
			Lower bound	Upper bound
Decline rate (%)	0.11	Normal	5% (0.06)	95% (0.16)
APG wellhead cost (£/kg)	0.09	Triangular	0.0	0.20
Redundant power (fraction)*	0.0	Triangular	0.0	0.75
Fuel heating value (kJ/kg)	45616	Uniform	41040	45616
Plant TCI cost (£/kW)	691.49	Triangular	440.70	1934.01
Interest rate for TCI recovery (%)	0.1	Normal	5% (0.06)	95% (0.12)
Capacity factor (hour/year)	7821	Normal	5% (7446)	95% (7796)
Fixed O&M cost (£/kW/year)	3.5	Triangular	3.0	7.5
Variable O&M cost (£/kWh)	0.00191	Triangular	0.00180	0.0193
Revenue tax (%)	0.25	Normal	5% (0.15),	95% (0.40)
Discount rate (%)	0.1	Triangular	0.08	0.15
Electricity price (£/kWh)	0.095	Uniform	0.065	0.1
Depreciation cost (£/kWh)	0.00354	Uniform	0.00350	0.00367

* Redundant unit is fraction of the plant capacity

The Probabilistic Predictions for NPV and IRR



(a)



(b)

Figure 4-22: (a) NPV and (b) IRR Predictions for Scenario-2 Based on the Total Effect of the Risk Variables

This scenario has mean NPV of £ 34.2 billion with 50% of the NPV below £0.351 billion. The scenario-1 mean NPV is greater than scenario-2 mean NPV value by is £66.9 billion. The uncertainty associated with 90 percentile of the NPV value in this scenario is associated with 75.78% change in electricity selling price;   and 25.1 changes in associated gas production cost; and 12.1%

change in specific TCI cost. The overall internal rate of return for this scenario is less than the scenario-1 by 9%. The uncertainty associated within the 10 percentile value of the IRR which is less -5% is 82.5% change in the specific TCI cost; 72.1% change in the associated gas production cost and 34.3% change in the selling price of electricity.

The Probabilistic Predictions of NPV and IRR in terms of URR

The uncertainty associated with gas production leads to treating its URR using probabilities designated by percentiles. The economic performance of utilization cannot be directly linked to the URR since there is no perfect correlation between them, Figure 4-25 (a-b) below; unlike that of URR and production decline rate, which exhibits a perfect correlation Figure 4-25 (c) below. Thus, predicting the economic performance for a given URR is done in terms of their probabilities expressed in percentiles. For instance, P10 of URR of the associated gas shows that IRR is -4.9% and NPV is below £ -210 million.

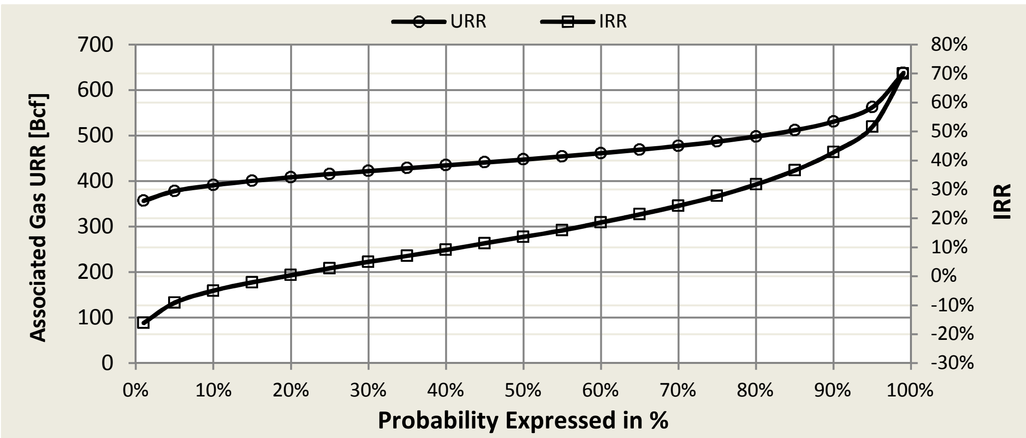


Figure 4-23: Change in IRR and Associated Gas URR using Percentile

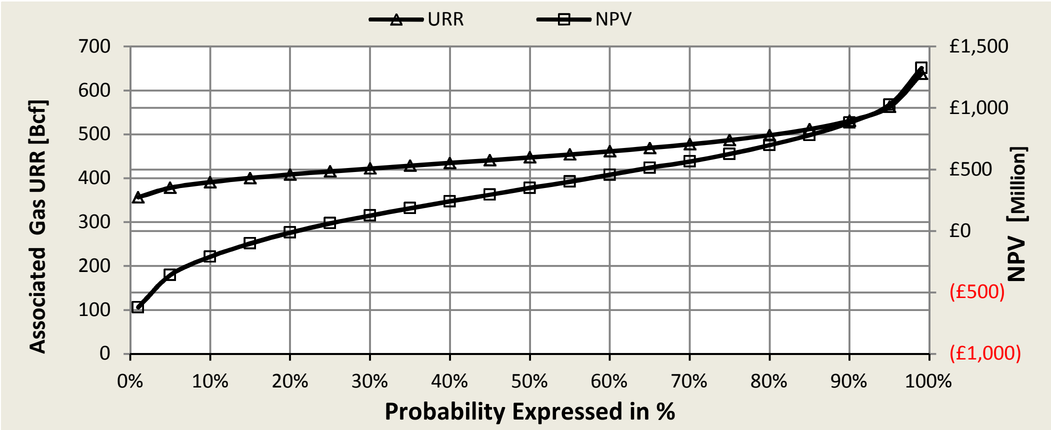
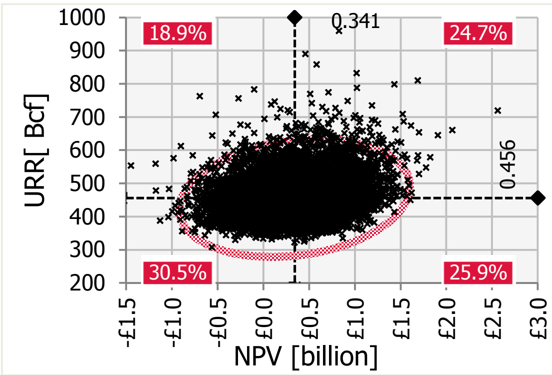
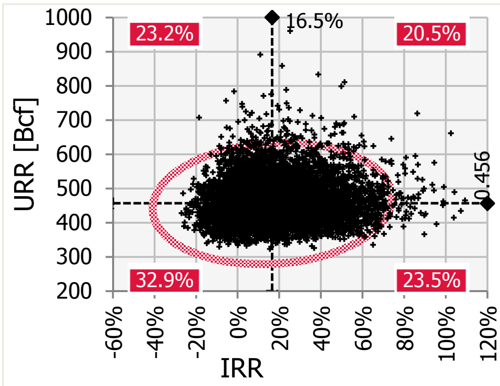


Figure 4-24: Change in NPV and Associated Gas URR using Percentile





(a)

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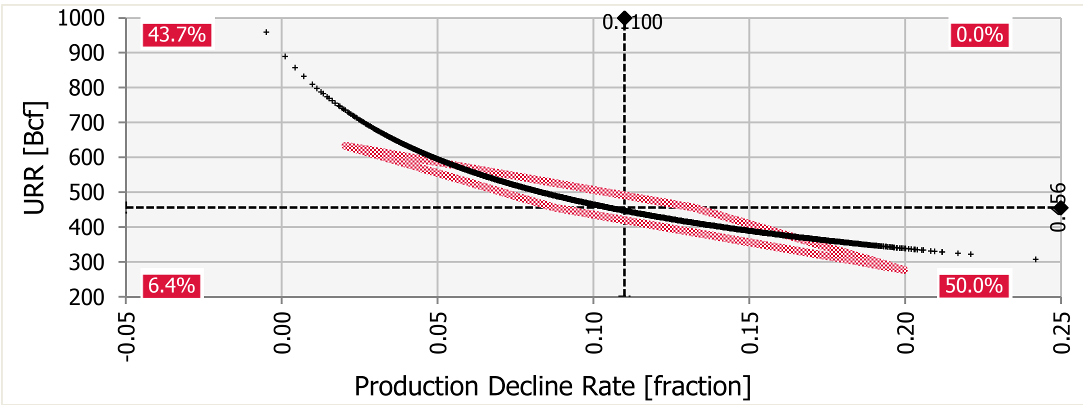


(c)

Figure 4-25: Correlation of URR with: (a) NPV, (b) URR and (c) Decline Rate

4.4 Scenario-3 Evaluation

4.4.1 Associated Gas Production Schedule

The third scenario is about 17 Bcf reserves or ultimately recoverable reserves having a production profile generated with the following assumptions:

- 25 years continuous production duration
- constant annual production decline rate
- depletion assumes harmonic decline curve
- decline rate within 6-16%
- initial production rate is 1.3 Bcf/year

The production profile for this scenario based on the assumptions listed above is shown in Figure 4-26 belowfor 6%, 12% and 16% decline rates. The MCS of the production profile using the above data set produce URR with a lognormal distribution. The URR in terms of P10, P50 and P90 for the production parameters is highlighted in Figure 4-27 below.

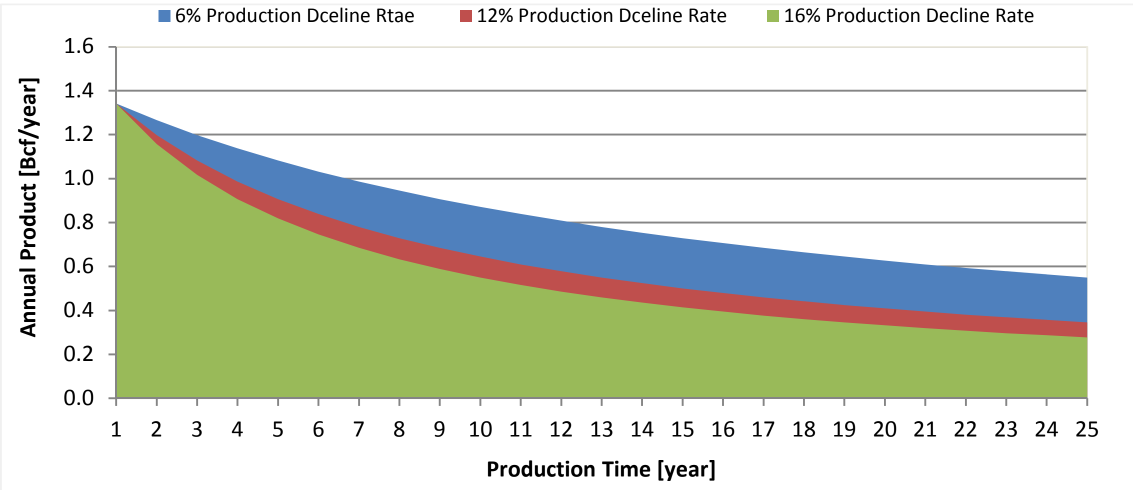


Figure 4-26: Scenario-3 APG Production History for Different Decline Rate

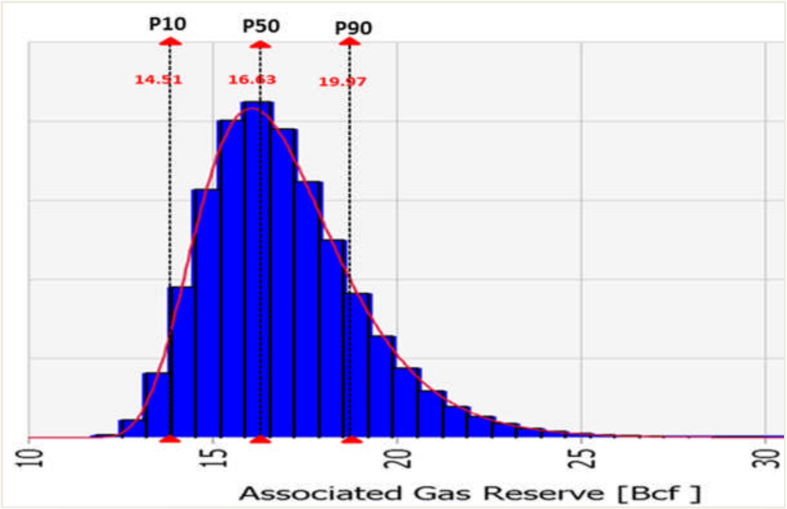


Figure 4-27: Scenario-3 URR Probabilistic Reserves

4.4.2 Engine Unit Selection

The engine fleet in senario-1 comprises of three sets of 5.3MW gas turbine. This is based on the initial associated gas production of 1.3 Bcf/year. The power plant capacity is found to about 15.9 MW. Table 4-9 below shows the mix of engine units, with power capacities, fuel consumptions and thermal efficiency. Arrangements and numbers of particular engine size were predetermined to enable divestment strategy simulations. This was technically done in line with production decline profile to suite redundant engine unit and their withdrawal/divestment timing.

Table 4-9: Engine Units Mix for Scenario-3

Power [MW]	202.4	98.1	85.0	50.5	30.2	27.2	11.2	5.3
Thermal Efficiency [%]	38.0	45.0	32.6	38.3	39.5	36.4	31.4	31.0
Number of Unit Used	x0	x0	x0	x0	x0	x0	x0	x3
Fuel Flow per unit [kg/s]	11.71	4.74	5.71	2.85	1.68	1.64	0.79	0.35

4.4.3 Engine Capital Cost Estimation

The total specific purchased equipment cost is the sum of the total costs of all the three engine units divided by the sum of the engine total output power. Total specific PEC for this scenario is calculated to be 300.70 $£_{2010}$/kW, see specific PEC estimation in chapter 3.

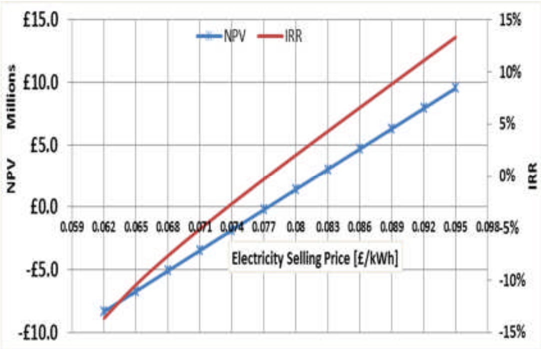
Table 4-10: The Scenario-3 TCI Cost Variables

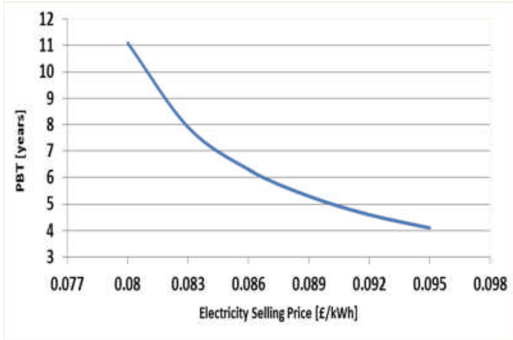
Total Capital Invest Component			Range of TCI Values (£/kW)		
I. Fixed capital investment (FCI)	***(A). Direct Cost, DC***	***5. Onsite Cost (ONSC)***	Lower value	Deterministic value	Upper value
		* Purchased equipment cost (PEC)	252.60	300.70	420.49
		* Purchased equipment installation	50.52	150.35	378.44
		* Piping	26.56	75.18	294.34
		* Electrical equipment & materials	25.26	36.08	63.07
		6. Offsite costs (OFSC)			
		Land	0.00	27.063	42.05
		Civil, structural & architectural work	37.89	70.08	378.44
		Service facilities	75.78	35.04	420.49
	(B). Indirect Cost	1. Engineering & supervision	63.15	90.21	315.37
		2. Construction cost			
		3. Contingencies			
II. Other Outlays		A. Start-up cost B. Working capital C. cost of licencing, R&D D. Allowance for fund used during Construction (AFUDC)	126.30	75.18	84.10
Specific TCI COST			**656.76**	**890.07**	**2396.79**

4.4.4 Techno-Economic Analysis

Table 4-11: Summary of Techno-Economic Parameters and Assumptions

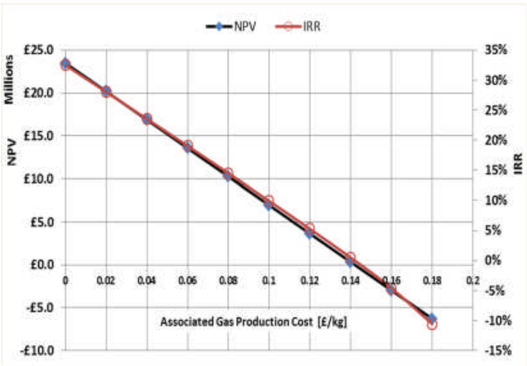
Parameter	Value
Nominal plant capacity (kW)	15900
Thermal efficiency (%)	31.0
Fuel heating value (kJ/kg)	45616
Site ambient temperature (K)	288.15
Associated gas URR (Bcf)	17
Initial gas production (Bcf)	1.3
Capacity factor (hour/year)	7623
Associated gas decline rate (%)	11
Plant specific total capital cost ($£_{2010}$/kW)	890.07
Associated gas production cost ($£_{2010}$/kg)	0.09
Fixed O&M cost ($£_{2010}$/kW/year)	0.67
Variable O&M cost ($£_{2010}$/kWh)	0.0011
Monetization duration (years)	25
Interest rate for TCI recovery (%)	10
Depreciation cost ($£_{2010}$/kWh)	0.0047
Electricity price $£_{2010}$/kWh	0.095
Emission tax = Flare reduction credit (%)	0
Revenue tax (%)	25
Discount rate (%)	15
O&M costs escalation (%)	2
Electricity price and gas escalation (%)	1

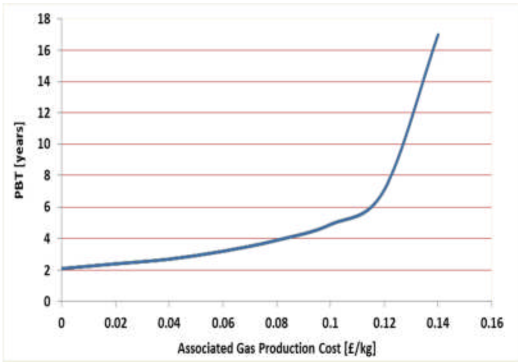




(a) (b)

Figure 4-28: Change in NPV IRR and PBT with Electricity Selling Price





(a) (b)

Figure 4-29: Impact of Associated Gas Production cost on NVP IRR and PBT

Following the anticipated increase in CoE due to increasing production decline rates, the impact of high electricity production cost is analysed. The results for the criteria selected for evaluation are shown in Figure 4-28 above. The economic performance assed based on 11% production decline rate, shows that selling price of electricity should be well above 0.77£/kWh for a fair economic justification given other conditions as stated for this evaluation in Table 4-11 above. Again from Figure 4-29 above, the cost of associated gas at above 0.14 £/kg, the NPV becomes negative and IRR will be well beyond 1%. Likewise, the impact of associated gas cost above 0.14£/kg on PBT will move from 17 years to a condition where the project will never breakeven within the 25 year utilization period.

4.4.5 Uncertainty and Risk Analysis – Probabilistic Approach

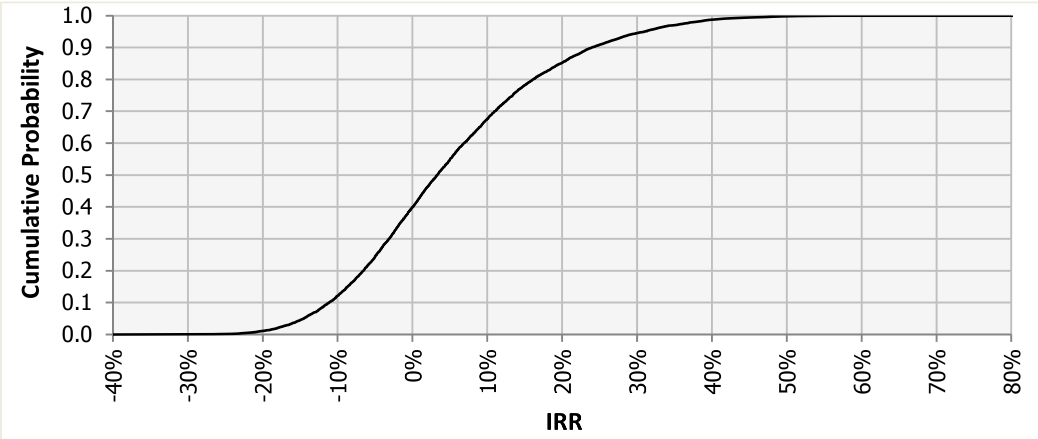
Similarly, Monte Carlo Simulation with 10000 iterations as before in scenario-1 and scenario-3 above is conducted with the probabilistic distribution for the risk variables as shown in Table 4-12 below and the result of this analysis is discussed afterwards.

Table 4-12: Probability Distributions for the Risk Variables

Risk variables	Deterministic value	Distribution	Distribution details	
			Lower bound	Upper bound
Decline rate (%)	0.11	Normal	5% (0.06)	95% (0.16)
APG wellhead cost (£/kg)	0.09	Triangular	0.0	0.20
Redundant power (fraction)*	0.0	Triangular	0.0	0.75
Fuel heating value (kJ/kg)	45616	Uniform	41040	45617
Specific Plant TCI cost (£/kW)	890.07	Triangular	656.70	2396.79
Interest rate for TCI recovery (%)	0.1	Normal	5% (0.06)	95% (0.12)
Capacity factor (hour/year)	7821	Normal	5% (7446)	95% (7796)
Fixed O&M cost (£/kW/year)	0.67	Triangular	0.34	0.90
Variable O&M cost (£/kWh)	0.0011	Triangular	0.0010	0.0015
Revenue tax (%)	0.25	Normal	5% (0.15)	95% (0.40)
Discount rate (%)	0.1	Triangular	0.08	0.15
Electricity price (£/kWh)	0.095	Uniform	0.065	0.1
Depreciation cost (£/kWh)	0.0047	Uniform	0.0024	0.0049

* Redundant unit is fraction of the plant capacity

The Probabilistic Predictions for NPV and IRR



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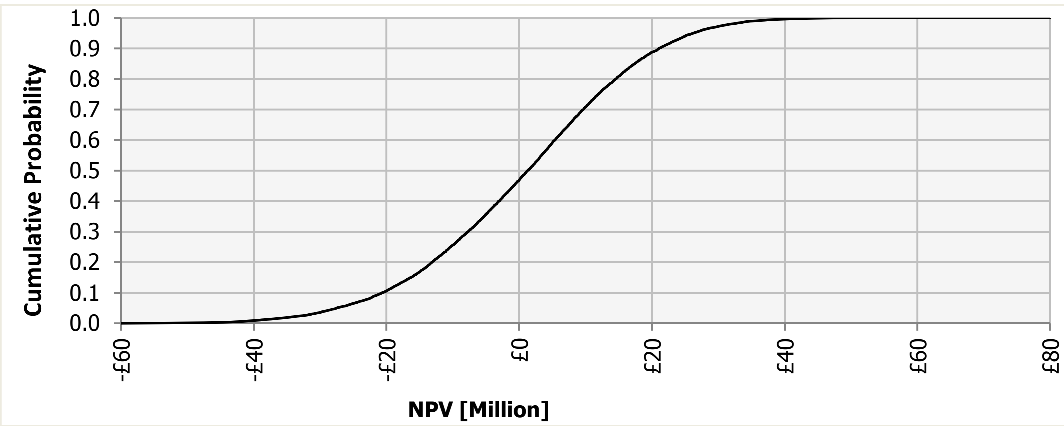


(b)

Figure 4-30: (a) NPV and (b) IRR Predictions for Scenario-1 Based on the Total Effect of the Risk Variables

This scenario has a mean NPV value of less than £0.6 million with 47.1% or approximately 0.47 probabilities that NPV value will be less than zero. The uncertainty associated with 90 percentile of the NPV value in this scenario is contributed with 70.78% change in electricity selling price; 23.37 changes in associated gas production cost; and 23.79% change in specific TCI cost. The uncertainty associated within the 90 percentile value of the IRR is contributed by 66.95% change in electricity selling price; 18.73 change in the specific TCI cost; 28.27% change in the associated gas production cost.

The Probabilistic Predictions of NPV and IRR in terms of URR

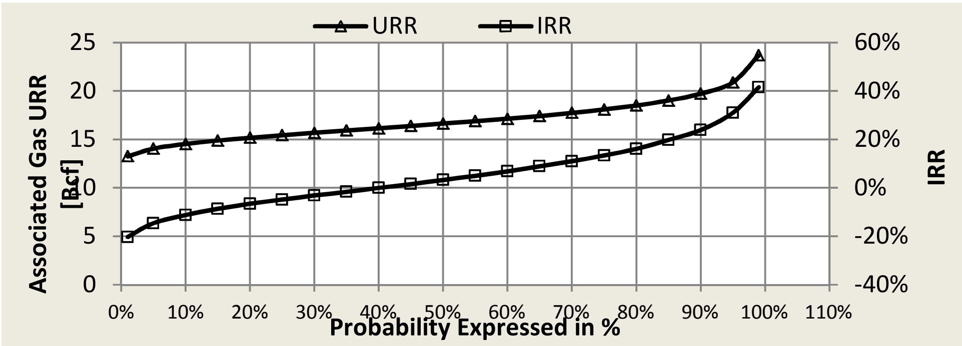


Figure 4-31: Change of IRR with Changing Associated gas URR

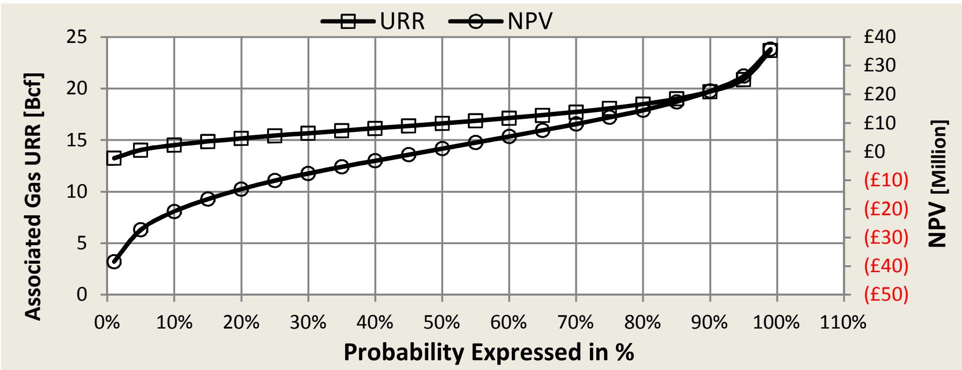


Figure 4-32: Change in NPV with Changing Associated gas URR

The predictions of the economic performance in this scenario in terms of URR probabilities- P10, P50 and P90 suggested that IRR will -11% for P10; 3.28% for P50 and 23.89 for P90. The NPV value for P10, P50 and P90 of URR will be below -20, 1 and 36 million respectively.

4.5 Comparison of the Three Scenarios

Based on the overall techno-economic parameters/consideration for this analysis, the three scenarios evaluated in this study are compared see Figure 4-33 below for the economic performance index values.

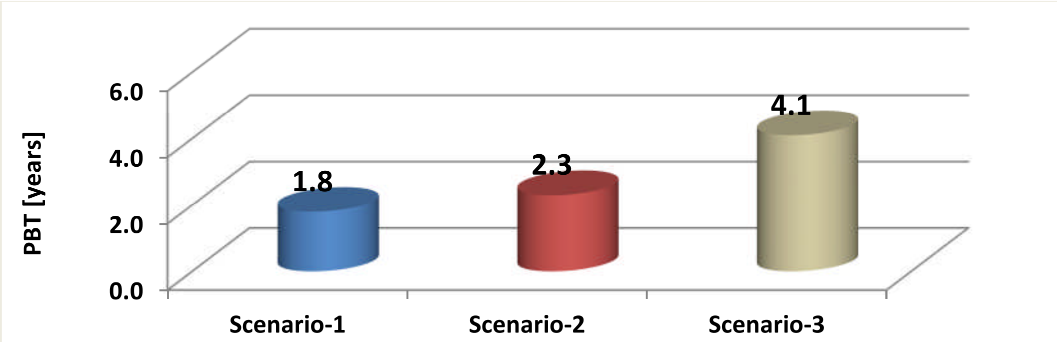
Starting with the pay-back time (PBT), and if this index is considered as the exposure of the investment to risk as suggested by [119], then scenario-3 is 2.3 times (56.1%) more exposed to risk than scenario-1; and 1.8 times (43.9%) more exposed to risk than scenario-2. Similarly, scenario-2 is ½ times (21.7%) more exposed to risk compared to scenario-1. Thus, scenario-3 (the smaller reserve) has more risk among the three scenarios while the scenario-1 (the highest reserve) has the least risk.

The internal rate of return (IRR) and net present value (NPV) among the scenarios is far batter in scenario-1 followed by scenario-2 with scenari-3 being the least. The comparison of the level of uncertainty associated with IRR, NPV and their variation to deterministic values considering the total risk variables indicates that:

1. **Scenario-3** is less than or equal to its deterministic value by 73.9% (i.e. approximately probability of 0.7) and 67.8% (approximately probability of 0.7) for IRR and NPV respectively;

2. **Scenario-2** is less than or equal to its deterministic value by 76.7% (approximately probability 0.8) and 64.2% (approximately probability of 0.6) for IRR and NPV respectively; and
3. **Scenario-1** is less than or equal to its deterministic value by 76.9% (approximately probability of 0.8) and 58.4% (approximately probability of 0.6) for IRR and NPV respectively.

This shows that, despite the fact that scenario-3 has least value of PBT, IRR and NPV its utilization is more stable compared to scenarios 2 and 3.



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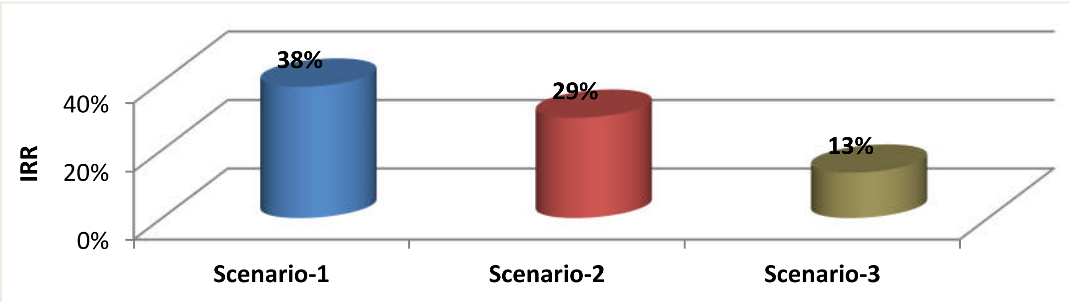

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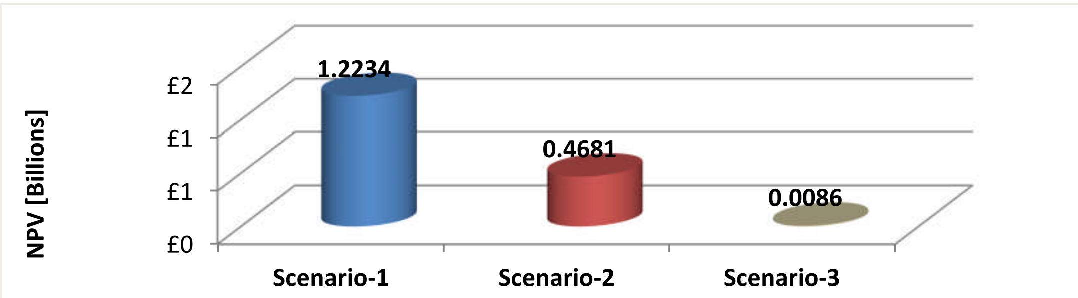


(c)

Figure 4-33: (a) PBT, (b) IRR, and (c) NPV Estimated Deterministic values

Chapter 5

Evaluation of Power Plant Models for Fuel Supply Schedule Decline Mitigation

5.1 Options for Power Plant Operations due to Decline

Power plants deployed for onsite utilization of associated gas can be prone to operational underperformance and poor economic outlook. This can occur due to spontaneous erratic associated gas supply schedule throughout production decline regime. As such, it has become imperative to develop and implement a power plant models that will adapt to operational changes as required during reduced associated gas supply schedule phase.

This chapter focuses on evaluation of power plant operational alternatives for production decline mitigation management from power plant performance and operational stance. In this study two alternative models for power plant operations were proposed. These alternatives are listed below as:

- Alternative 1: Engine units divestment model

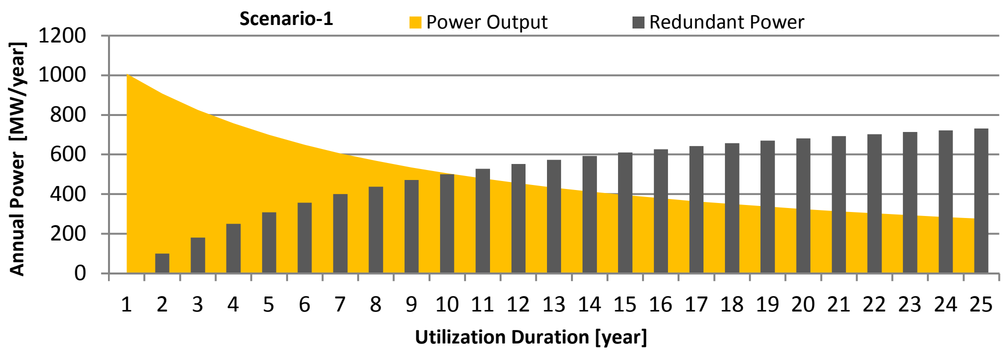
- Alternative 2: Makeup-fuel model

These two alternatives are evaluated and compared against each other for a certain production decline rate under the three reserves size scenarios. The advantages and limitations of each option are also compared with the part-load power plant operations option. The amount of reduced part-load operations with each scenario is evaluated. Reduced part-load operations will increase the availability of the power plant and reduce operational cost of the power plant. Though running some power plant on part-load can be considered a normal practice for power generation. This can be attributed to factors such as changing demand load profile. Thus, in the absence of other factors leading to operating power plant on part-load, this study exclusively dealt with part-load operations initiated by production decline. The extent to which part-load operations dominated power plant operation under the decline rate being considered is quantified between alternative 1 and 2 using the three associated gas URR scenarios.

5.1.1 Power Plant Redundant Units

The annual cumulative redundant capacities of power plant from the initial plant capacity are shown in Figure 5-1 below for the three scenarios. Each of the plots is generated based on the 11% production decline rate. The implication of continuous annual reduced power output is a reduced capacity factor that eventually increased the CoE over time. This yields a low return rate on the investment; and increased decline rate also will prolonged pay-back period. Thus, increasing the investment risks associated with onsite utilization of associated gas for power generation.

Based on the production decline model for this study, the worst reduction in capacity factor is in the first quarter of the utilization period. This reaches approximately 45% in the first quarter with average annual 6% reduction in capacity factor throughout the rest of the utilization duration. This trend is same with the three scenarios; since the decline rate and utilization duration is assumed to be the same in all the scenarios.



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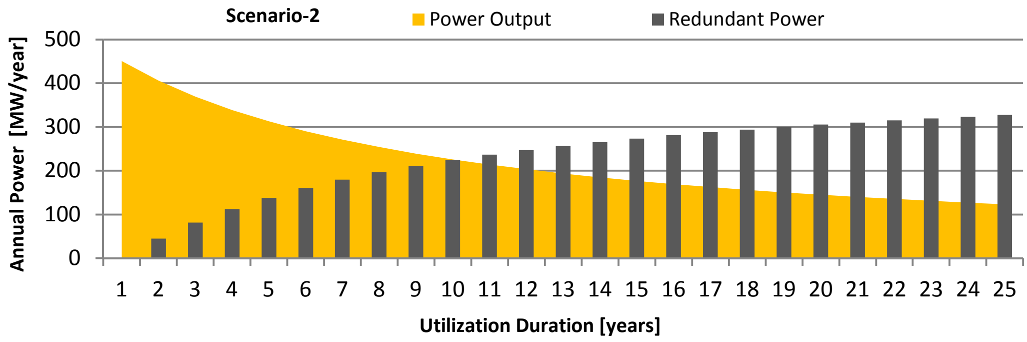

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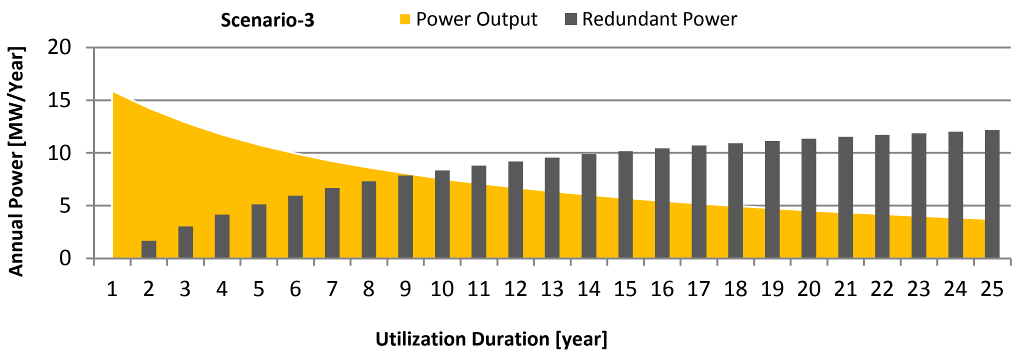


(c)

Figure 5-1: (a) Scenario -1, (b) Scenario-2 and (c) Scenario-3 Redundant Power due to Reduced Associated Gas Schedule

5.2 **Engine Units Divestment Model**

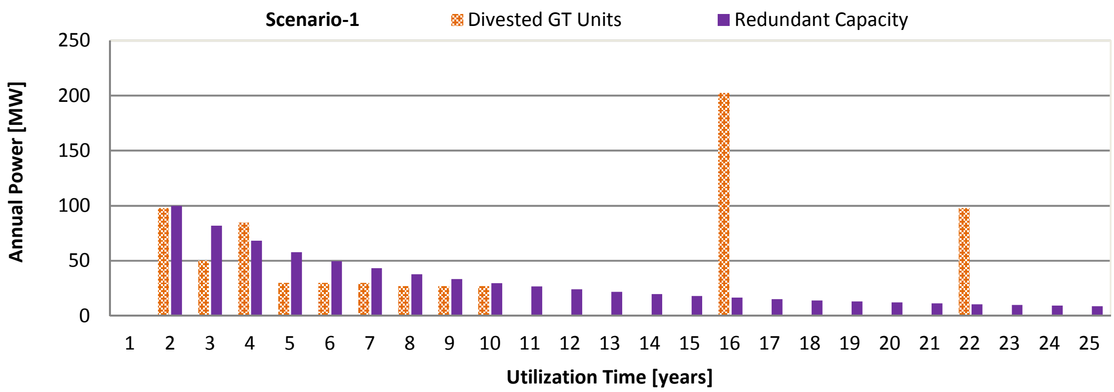
Gas turbines unit divestment option for mitigation of production decline involves selection of engine units and managing redundant engine unit. For a particular power plant, and associated gas production profile the withdrawal timing and appropriate engine unit to be withdrawn will be a major target. The two factors affecting the amount of redundant GT engine unit are the decline rate and associated gas URR.

The gas turbine unit divestment algorithm relies on output from associated gas production profile module to predict the power plant engine mix. At the same time this prediction is based on available engine in the library (i.e. within the eight gas turbine engines for this study). Determination of particular gas turbine unit due for divestment is estimated using performance and economic parameters. In the performance parameter criteria, the engine thermal efficiency and fuel consumption are the factors considered. While the economic criterion is attributed to the gas turbine unit PEC cost.

5.2.1 Technical Evaluation of Power Plant Divested GT Unit

Depending on the GT unit arrangement for a particular power plant, divestment can be made more effective. In scenario-1, 11 gas turbine units from the 13 engine units of this scenario were divested. Each of the engines was divested in different years. Scenario-2 with a total of 7 engines has 6 of the engine units divested. Two engine units (11.2 and 5.3MW) were divested at the second year and another two gas turbine units (27.2 and 5.3MW) were also divested at the third year. The remaining two divested engine units were divested in separate years afterwards. Scenario-3 with a total of 3 engines divested 2 of its engine units in separate years. Figure 5-2 below shows number of GT engine and their divestment time for each scenario.

There is no common divestment pattern across the three scenarios. The number of divested engine units can be a function of engine unit arrangement. This will be different for different associated URR and production decline rates. It was observed that increasing associated gas reserve size, and production decline rate will increase the required gas turbine units and different sizes. Thus gas turbine unit divestment will be more frequent. On the contrary, the fewer engine units deployed for utilization of big reserves for high rate of production decline; power plant part-load operation will increase. Apparently capacity factor will be highly reduced. Therefore, there should be a trade-off between numbers and sizes of gas turbines deployed and allowable limit for part-load operations. This can only be estimated once accurate associated gas production profile is established. Thus prediction of associated production profile is central to divestment application.



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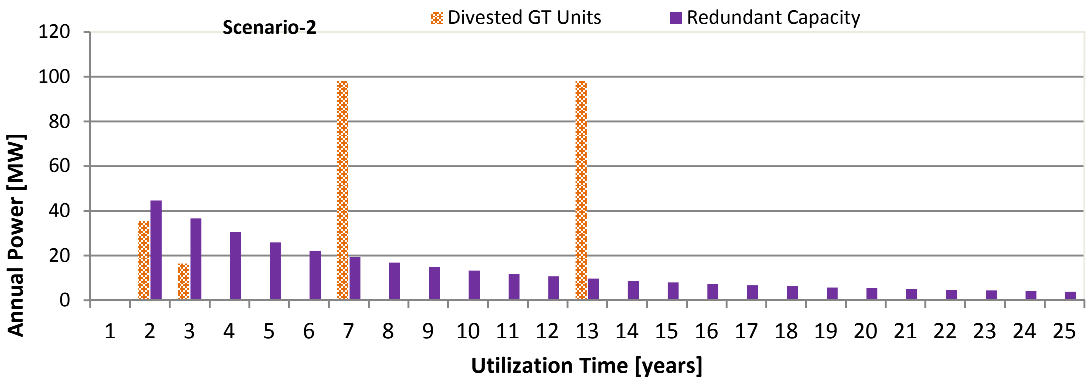

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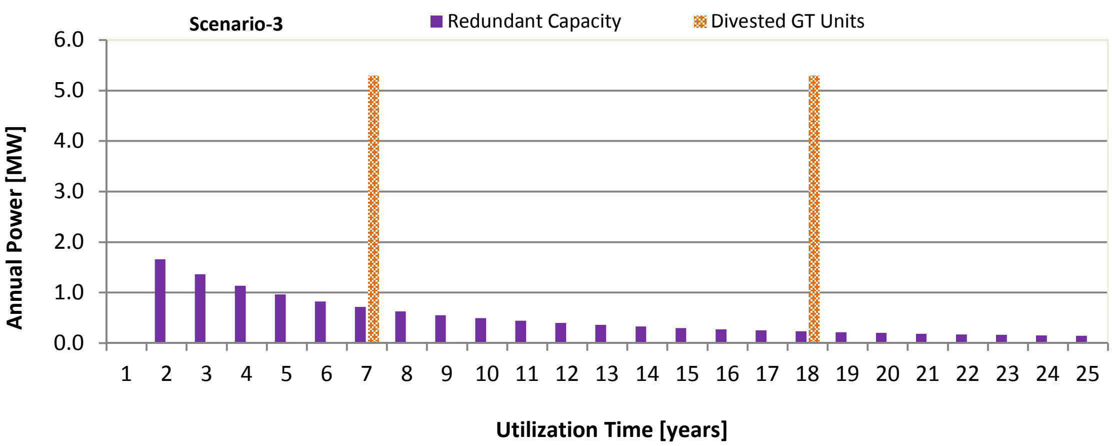


(c)

Figure 5-2: (a) Scenario-1, (b) Scenario-2 and (c) Scenario-3 Capacity and Time of Divested GT Units

5.2.2 Power Plant GT Unit Divestment Economic Evaluation

The results for the criteria selected for evaluation are shown in **Error! eference source not found. Error! Reference source not found.**. Electricity tariff of 0.08£/kWh is used for this analysis and other parameters remains the same. The performance of three power plants scenarios were analysed, with and without divestment application. The economic performance improvement with divestment stratagem was quite evident across the three power plants. The economic condition of reference power plant (without divestment) in scenario-3 indicates that initial capital outlay will not be recovered during the economic life the power plant having a PBT value stated as beyond[7].

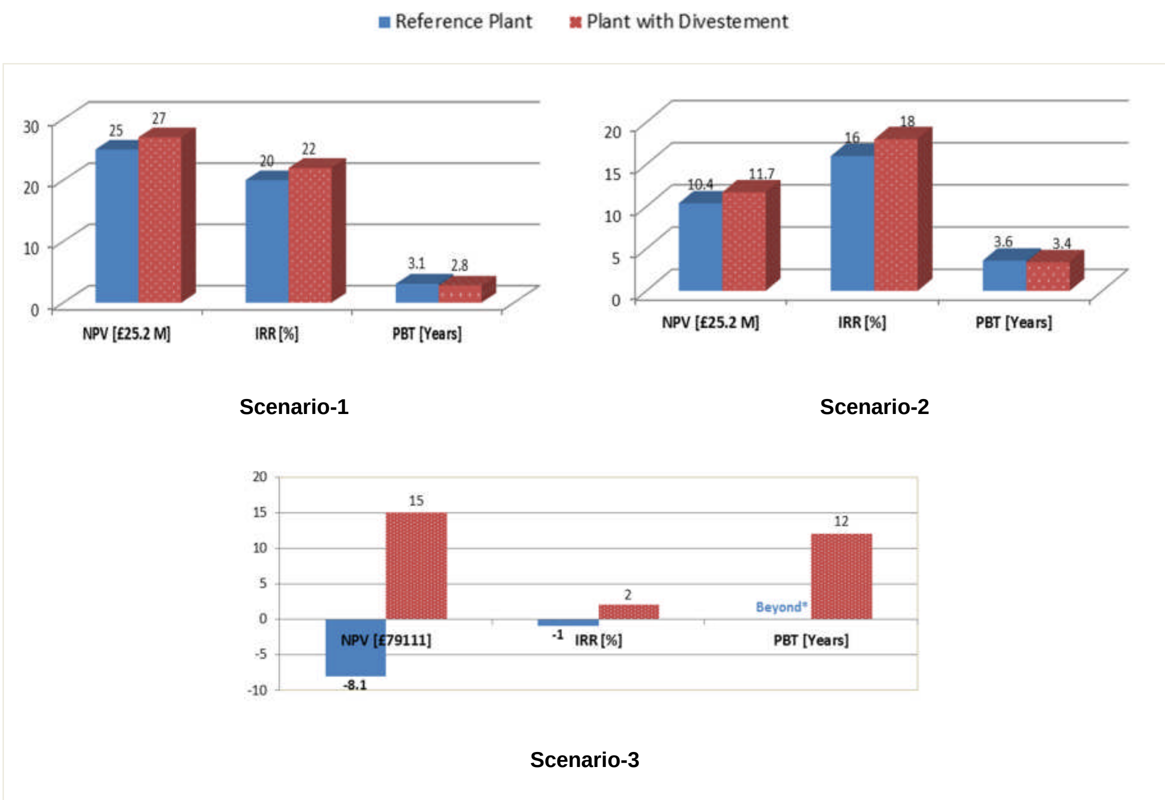


Figure 5-3: Main Economic Results with and without GT Units Divestment Stratagem for all the Scenarios

[7] (*) beyond indicates the PBT is outside of the plant economic life being considered, in this case 25 years period. This means that the all things being equal the capital investment will not be recovered in this case.

The economic performance of the same scenario-3 with divestment recovered significantly having a PBT within 12 years. This further corroborated with a positive NPV and improved IRR as highlighted. In addition, the effectiveness of the divestment stratagem tends to increases with increasing URR as seen between scenario-1 and scenario-2. Since the number of gas turbine units is more in scenario-1 than in scenarios-2 and scenarios-3, a definite conclusion on the source of this trend becomes difficult to reach.

5.3 Power Plant Makeup-Fuel

The makeup-fuel option is envisaged to be one of the alternatives to mitigate erratic associated (fuel) schedule seen during production decline regime. Depending on proximity of power plant to the makeup-fuel sources, this alternative may as well involve storage facility. Considering weight and space related issues in offshore drilling platforms this will be additional complexity when utilization power plant is located offshore. Apparently the capital cost of this option will increase under these conditions and even more since logistics of bringing makeup-fuel will obviously increase.

Analysis of this alternative can be complex depending on the scope and number of factors being considered. For instance, from power plant performance view point, different grades of makeup-fuel can be considered resulting to so many performance outcomes. Likewise, parameters required for economic evaluation of such circumstances for best option will increase.

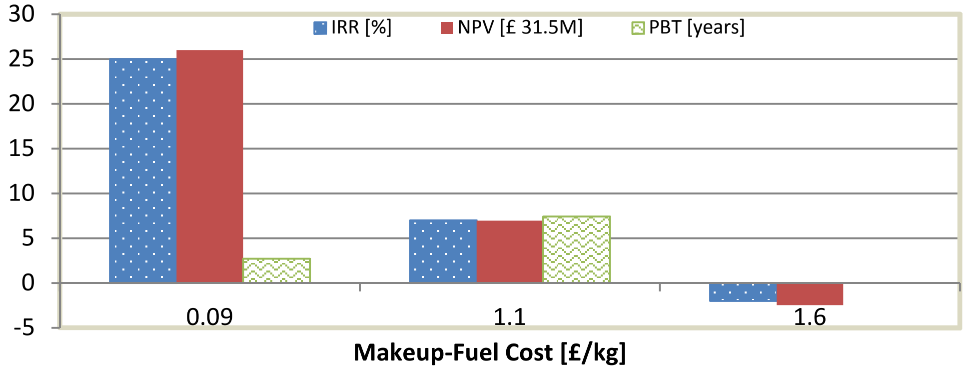
5.3.1 Technical Evaluation of Power Plant Makeup-Fuel

Based on gas turbine performance results with different fuels in chapter three, considerable variation in fuel properties is subject to gas turbine unit modification. This will increase the gas turbine specific PEC and without increase in GT performance parameters like thermal efficiency, the CoE will go high without cheaper fuel. To minimise evaluation complexity the properties of makeup-fuel considered here is the same grade as the associated gas. Quantities of makeup-fuel required increases with increasing URR capacity for the same production decline rate. This is only a fair hypothetical situation for harmonic production decline curve. It was assumed that decline starts immediately with production and remains constant throughout the reservoir economic producing life. However in reality production profile is dictated by physical and manmade/operational factors. In the scenarios considered here about 58 Bcf of makeup-fuel is required for scenario-1 and 26 Bcf for scenario-2 and 0.97 Bcf for sceanrio-3.

5.3.2 Economic Evaluation of Power Plant Makeup-Fuel

The results for economic criteria for using makeup-fuel are shown in Figure 5-4 below with changing fuel cost at electricity tariff of 0.08 £/kWh. The value of IRR, NPV and PBT when makeup-fuel cost is the same as associated gas cost will typical represent the economic performance without production decline. The option of running power plant on makeup-fuel seems better than reference power plant within certain price of makeup-fuel only. In this case this value lies below 1.1 £/kg for scenario-1 and scenario-2. Within the same value of makeup-fuel tariff, scenario-3 is not favoured.

This result is interesting because it indicate increasing makeup-fuel sensitivity with decreasing associated gas utilization power plant. This is evident from the NPV, IRR and PBT which decreases with increasing price of associated gas in scenario-1 and scenario-2 and completely yield negative values in scenario-3. Since makeup-fuel from other location will always be greater than associated gas fuel for the same grade, then this result highlight the importance of using cheaper for makeup-fuel. In addition power plant deployed for associated gas utilization will be better with makeup-fuel option when production decline rate is considerately high.



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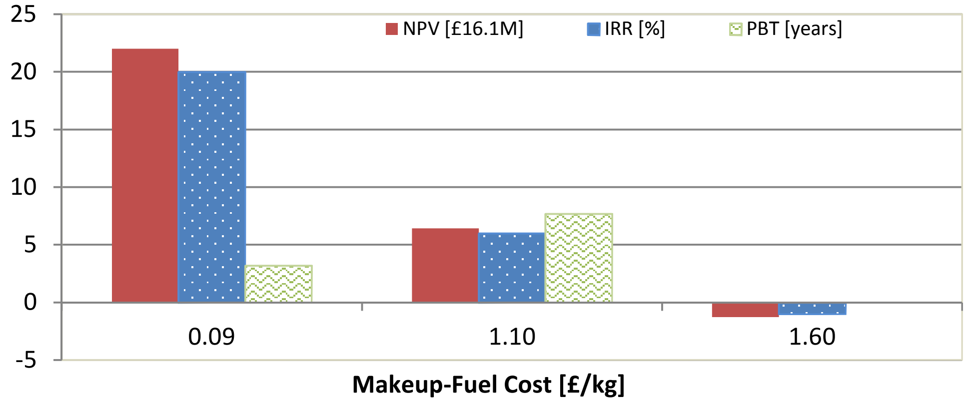

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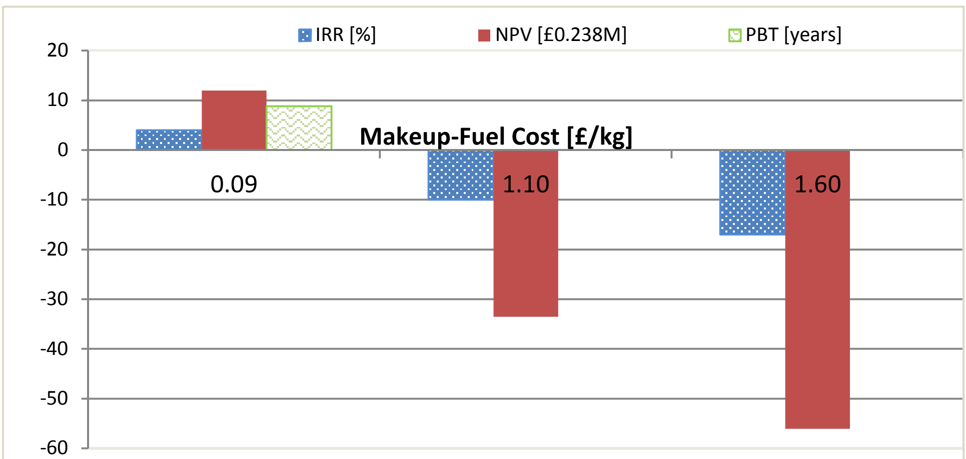


(C)

Figure 5-4: Economic Result for (a) Scenario-1, (b) Scenario-2 and (C) Scenario-3 with Makeup-Fuel for Varying Cost of Makeup-Fuel

5.4 Comparison of GT Divestment with Makeup-Fuel Option

It is quite difficult to compare the engine unit divestment and makeup-fuel option for mitigating production decline. The option suitable for a particular scenario will depend on several factors. This will include the degree of production decline rate; ability of the gas turbine unit to run on part-load; availability of makeup-fuel; type of power plant cycle and so on. Both options have advantages and disadvantages. For instance, part-load operations caused by decline will occur more frequent with gas turbine divestment alternative compared to makeup-fuel alternative. This suggests that divestment alternative will be more prone to emission since gas-fired power plant produces more emission on low power settings. On the other hand, this can be more for the makeup-fuel alternative when lower BTU grades fuels are used for makeup-fuel.

The makeup-fuel option will involves sustaining fuel supply schedule that is constantly changing according to decline and production profile. Hence, the makeup-fuel could require extra facilities like storage facility. This will increase investment capital cost and consequently increasing CoE. On the other hand divestment option is straight forward especially when the power plant is combustion turbine type. Is worth mentioning that combined power plant will be more beneficial but upgrading the combustion turbine to a combined cycle power plant will be more beneficial for makeup-fuel option than for divestment approach. Technically, this is because gas turbine engine divestment option will hardly maintain a specific performance parameters required for the steam cycle. The option to use to mitigate production decline will be more site specific.

Chapter 6

Onsite GT Utilization of Jones Creek Field Associated Gas

6.1 The Jones Creek Oilfield

The Jones Creek Field is located in the Niger Delta region of Nigeria. This field was discovered in 1967 with up 46 wells drilled in 2004 of which four of the wells were abandoned at that time [120]. This field is just about 45km from Warri which makes it practically ideal site for GTW selected to test the methodology developed in this study. Quite amount of associated gas from this field is originally transported to Lagos via pipeline. The field location with major cities surrounding it is shown below.

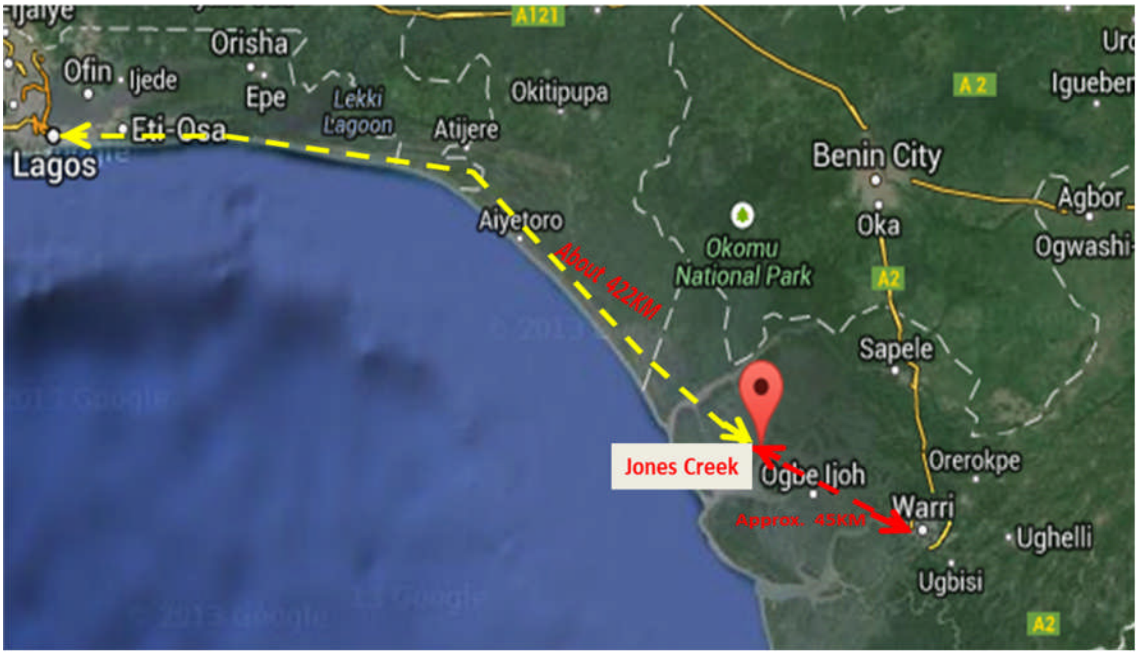


Figure 6-1: Google Map Showing Location of Jones Creek to Warri and Existing Gas Pipeline to Lagos

6.2 Production Profile

The Jones Creek started production in 1969, reaching its peak production in 1972. The ultimate recovery of this field as at 01/01/2004 was 835.9 mmstb of oil and 592.5 mmscf of gas. Oil and gas production as that time was of 553 mmstb of oil and 361 mmscf of gas. Thus, oil and gas ultimate recovery reserves remaining unexploited in that field after 37 years of production is about 34% and 39% respectively with an increasing production decline. The above field production performance information is extracted from environmental impact assessment of FDP of Jones Creek Field [120].

Most Nigerian reservoirs production has gas-oil ratio usually at 50:50. The data for oil production profile of Jones Creek Filed [121] is adapted for the associated gas production profile using the above GOR information, Figure 6-2. The production profile had significant production decline including those from major disturbances —changes in oil price and sabotage. Power plant associated gas utilization for 28 years period from 1972 to 1999 before the major disturbance from sabotage is evaluated. The associated gas URR based on production history with this period is about 71.0 Bcf.

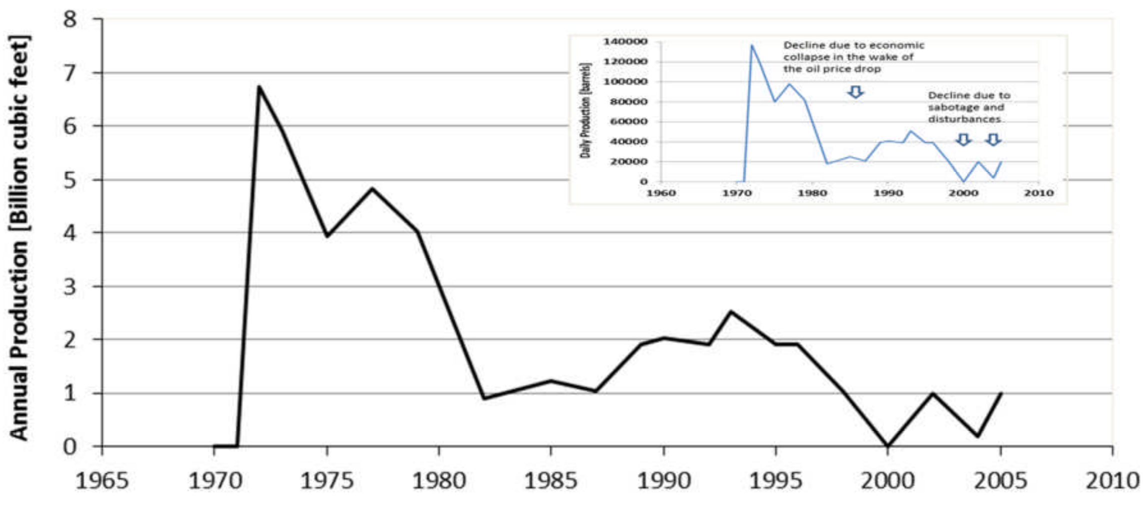


Figure 6-2: Production Profile of Associated Gas from Jones Creek Adapted from Oil Production Profile [121]

6.3 Selection of Gas Turbine Units for Power Plant

The power plant consists of two gas turbine engine sets selected from engine library as shown in Table 6-1. These two gas turbine units are preferred for this associated gas utilization based on the gas production history and ability of these engines to run on lower power settings. The gas turbine with nominal output power of 98.1 MW has net power output between 91.8 - 87.6 MW due to site ambient temperature level and fluctuation; see temperature profile in chapter three. Similarly, the second gas turbine engine with nominal power capacity of 30.2 MW under the same site ambient temperature profile has its output power between 25.2 - 17.5 MW. Both gas turbines are aeroderivative engines, see chapter three for full configuration detail of both engines.

Table 6-1: Gas Turbine Engine Units Combination

Power [MW]	202.4	98.1	85.0	50.5	30.2	27.2	11.2	5.3
Thermal Efficiency [%]	38.0	45.0	32.6	38.3	39.5	36.4	31.4	31.0
Number of Unit Used	x0	x1	x0	x0	x1	x0	x0	x0
Fuel Flow per unit [kg/s]	11.71	4.74	5.71	2.85	1.68	1.64	0.79	0.35

The estimated annual power yield based on associated gas production history is shown in Figure 6-3 below. The associated gas production profile compels the two engines to operate on fluctuating part–load conditions as shown in Figure 6-4 below.

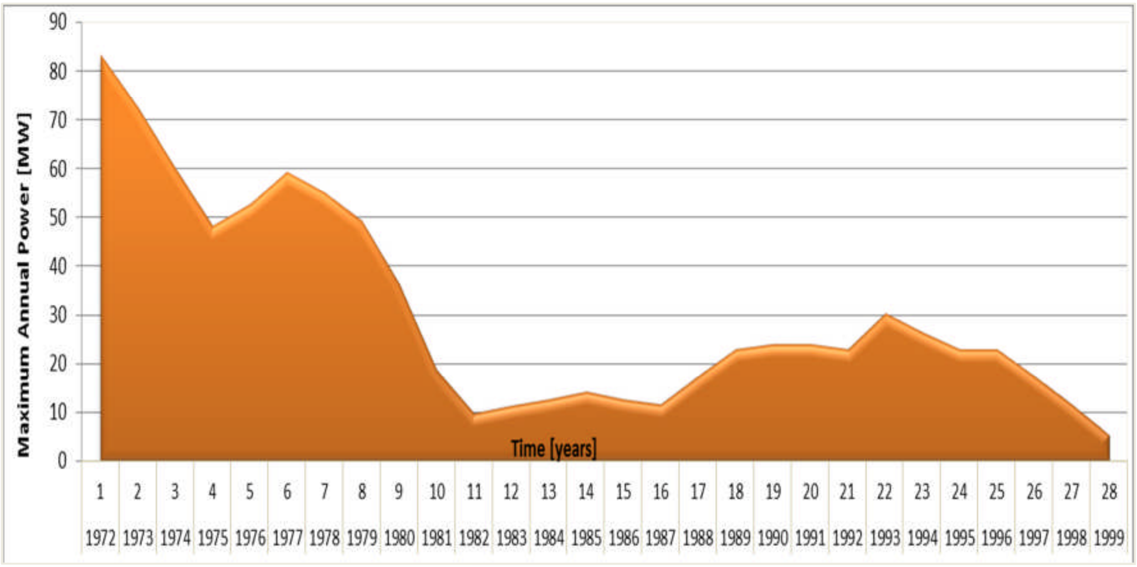


Figure 6-3: Annual MW based on Production profile

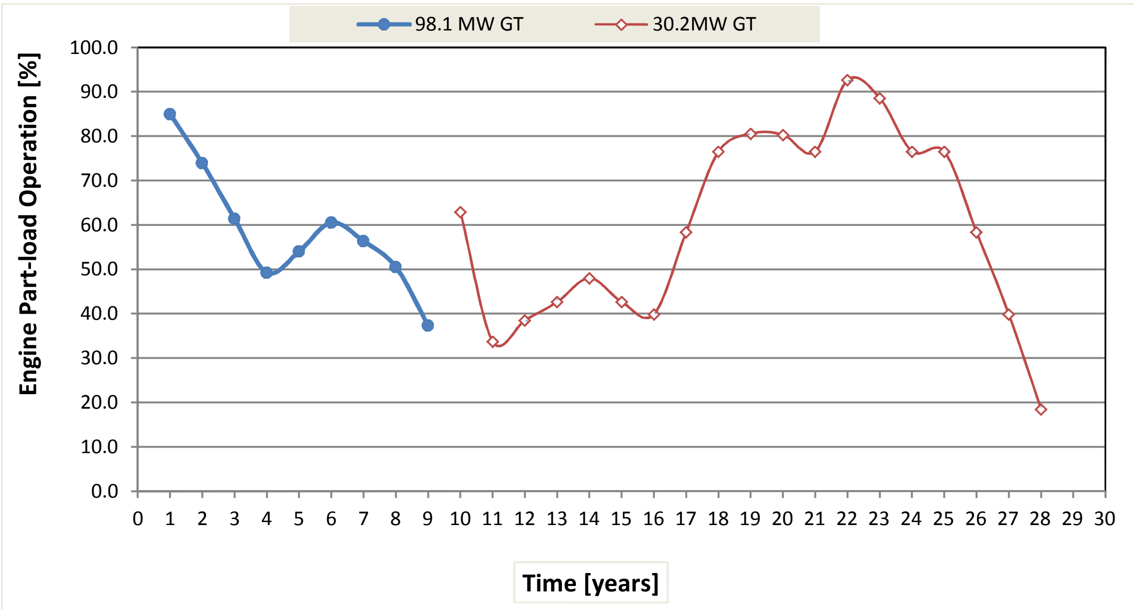


Figure 6-4: Part-load Operation of the Selected Engine Units during utilization Period due to Production Profile

6.3.1 Engine Capital Cost and Power Plant Estimation

The gas turbine units PEC is first estimated using the engine's power output capacity and thermal efficiency. Then, the total power plant investment (TCI) cost is then estimated using total gas turbine specific PEC and other cost outlays. This procedure is well documented and explained in the previous chapters 3 and 4. The TCI cost for this plant based on the two set of gas turbine units using this procedure is estimated as 1015.52 £/kW. For other economic assumption in this case study see Table 6-2.

Table 6-2: Summary of Techno-Economic Parameters and Assumptions

Parameter	Deterministic Value
Nominal plant capacity (MW)	83.4
Thermal efficiency (%)	varies
Fuel heating value (kJ/kg)	45616
Site ambient temperature (K)	varies
Capacity factor (hour/year)	7623
Plant specific total capital cost ($£_{2010}$/kW)	1015.52
Associated gas production cost ($£_{2010}$/kg)	0.009
Fixed O&M cost ($£_{2010}$/kW/year)	1.5
Variable O&M cost ($£_{2010}$/kWh)	0.0014
Monetization duration (years)	28
Interest rate for TCI recovery (%)	10
Depreciation cost ($£_{2010}$/kWh)	0.0048
Electricity tariff $£_{2010}$/kWh	0.080
Revenue tax (%)	25
Discount rate (%)	15
O&M costs escalation (%)	2
Electricity price and gas escalation (%)	1

The two gas turbine units have high thermal efficiencies which resulted to high specific capital cost for the plant. Though this is compensated for with their unique thermodynamic OD performance during part-load operations which make them engine of choice for this production profile. However, the slight reduction in thermal efficiencies associated with lower power settings increases the cost of energy (Figure 6-7 below) and CO_2 emission production. Generally, these are among the major disadvantages of running the gas turbine units on part-loads for long period of time.

The deterministic results based on the above techno-economic parameters showing onsite production cost of electricity is depicted in Figure 6-5. The economic appraisal criteria NPV, a discounted IRR and PBT are £39.2 Million, 10% and 5 years respectively, Figure 6-6 below. This shows a promising result but at the same time highlighting the risk element judging from acceptable hurdle rate of at least 20% rate of return and a pay-back time within 5 years of similar ventures. Further information on economic risk analysis may be required and decision seems subjective depending on the risk predisposition of the investor.

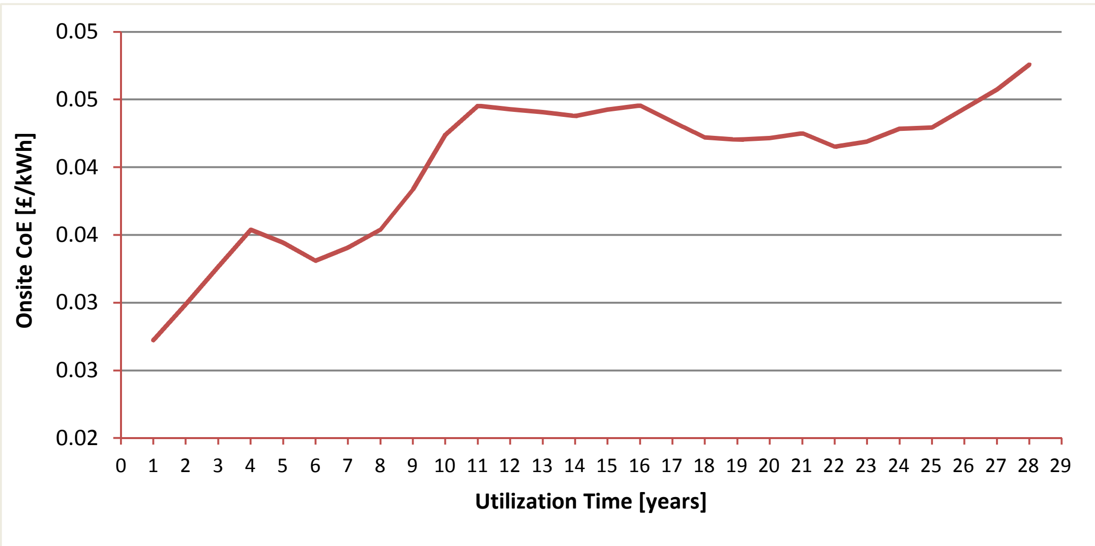


Figure 6-5: Annual Change in CoE during Utilization Period

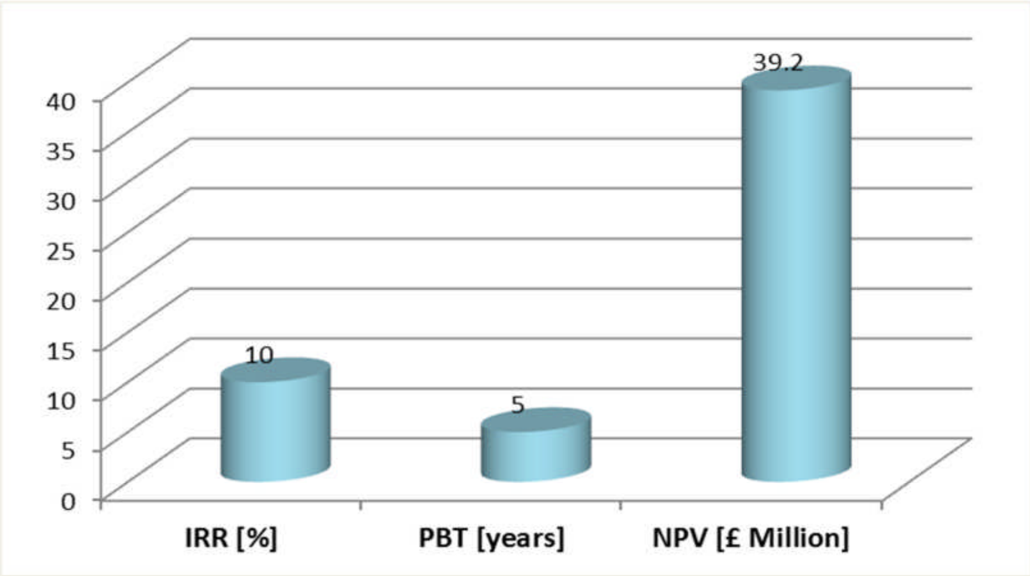


Figure 6-6: Economic Appraisals Results

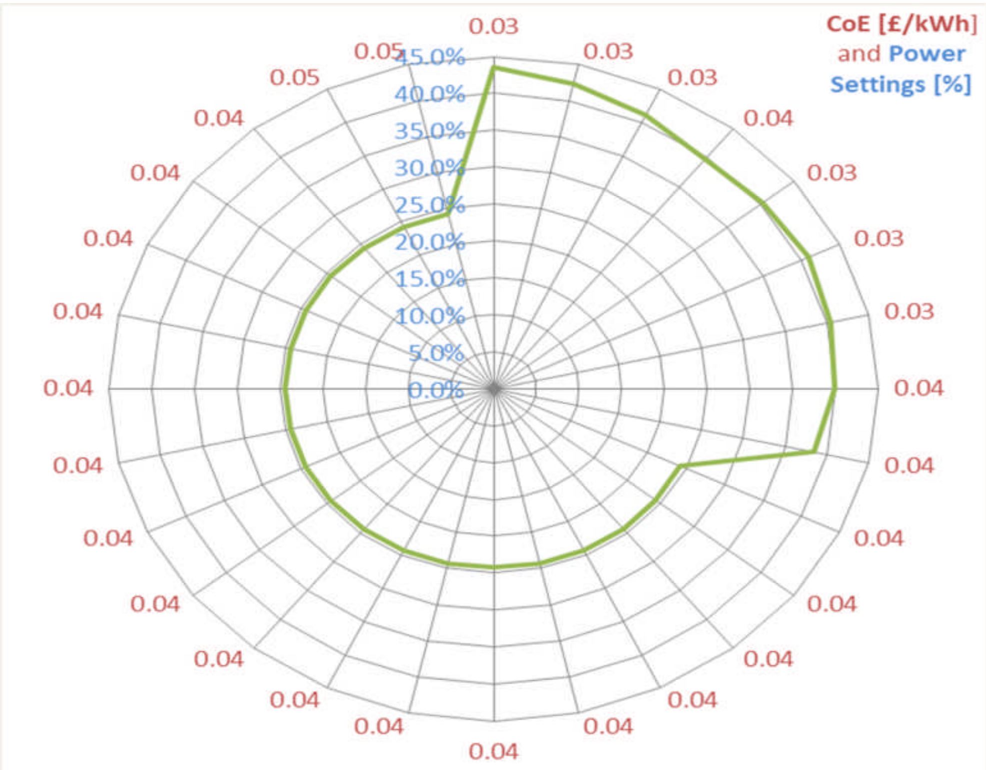
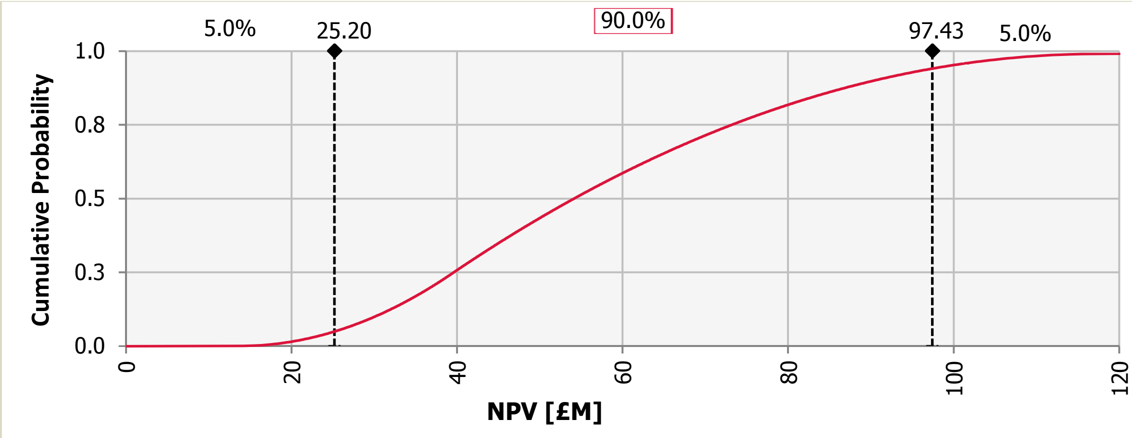


Figure 6-7: The Variation of CoE vs. Gas Turbine Units Thermal Efficiencies

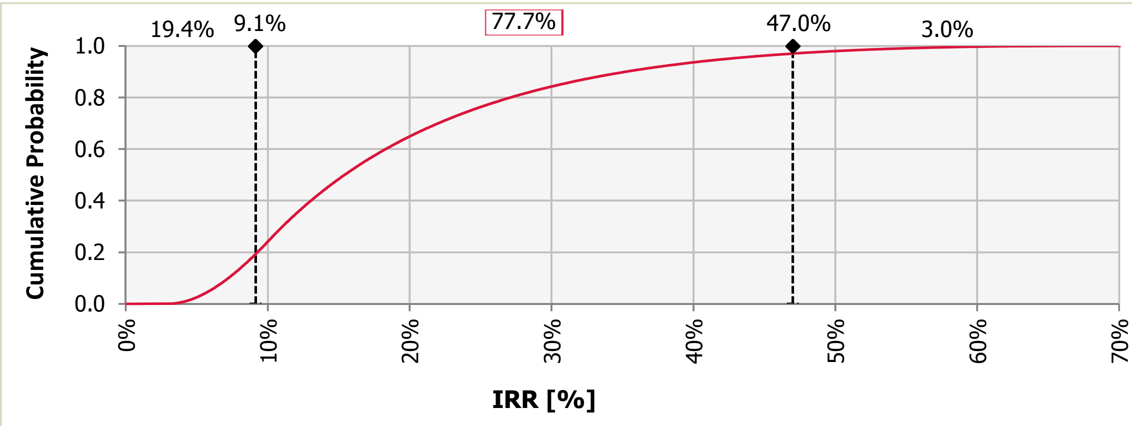
6.4 Economic Uncertainty Analysis – Probabilistic Approach

The power plant TCI cost is estimated with all the capital outlays characterised with uncertainties. Thus the power plant specific TCI cost is prone to changing the overall economic results. For instance most of the cost outlays will vary with location, like the labour cost and depending on remoteness of the site. The uncertainty in specific TCI cost is captured by replacing the deterministic value with a probabilistic distribution represented with a triangular distribution. The lower bound, upper bound and most likely value of the TCI cost triangular distribution is 450 £/kW, 1200 £/kW and 1015.52 £/kW respectively. Analysis of this kind presents better and dependable results compared to the deterministic one, providing decision-makers with lot more information.

The probabilistic values for NPV, IRR and PTB estimated by running 10000 iterations with Monte Carlo simulation are shown Figure 6-8 in cumulative probability format. The results indicated that considerable levels of uncertainty are associated with variation in TCI cost. The impact of this alone would cause the NPV to vary between £17.0M and £120.0M, with about 25% chance that this value will be below the deterministic NPV value of £39.2M in the cases simulated. At the same time the IRR vary between 3.5% and 70.0% with about 24.2.4% chance of being less than the deterministic IRR value of 10%. The PBT vary between 0 year and 8 years with about 24% chance of being above the deterministic PBT value. In Figure 6-8 (a), the 90.0% shows that chance of NPV being between £25.20M and £97.43M is about 90%; 77.7% for IRR and 80% for PBT is read the same as NPV.



(a)



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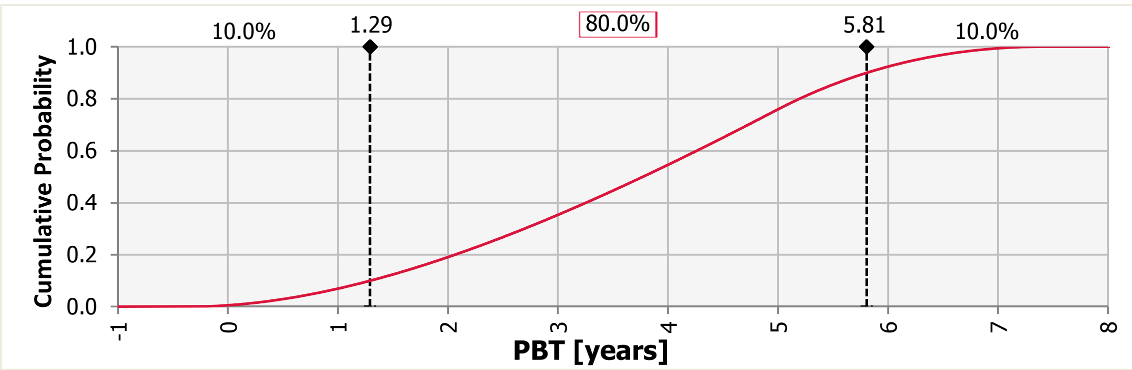


(c)

Figure 6-8: (a) NPV, (b) IRR and (c) PBT Predictions Considering Effect of Uncertainty in TCI Cost Estimation

6.5 Power Plant GT Unit Divestment Evaluation

The gas turbine unit mix involves optimization process to achieve a combination of engine units that will yield optimum divestment time and to ensure that the appropriate gas turbine unit will be divested. This is only based on a definite associated gas production profile and any variation in production profile during utilization will cause huge change in power plant operation initially defined. To counter this, gas turbine part-load operation is evaluated and utilised to accommodate reasonable changes during associated gas production. The gas turbine unit divestment alternative and evaluation approach as discussed in section 5.2 is used in view of finding the best economic result. Figure 6-9 below show the combined result of the operational mode and divestment timing for the best economic outlook.

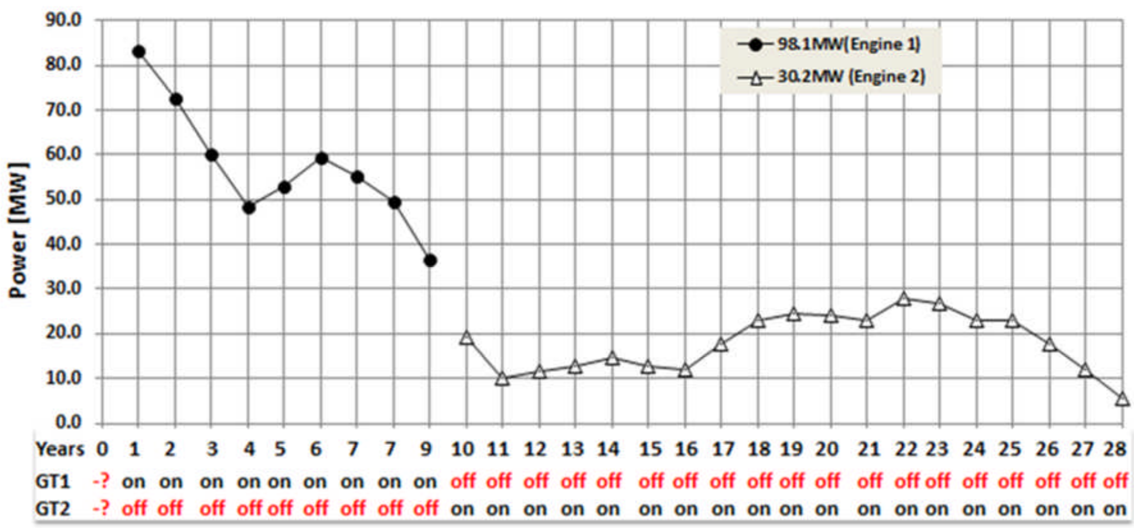


Figure 6-9: Power Plant Operational Mode and GT Units Divestment Timing

Here because the second gas turbine unit, the 30.32 MW is off for the first nine years, the result of the optimization is suggesting that capital investment should be carried out in two phases. Thus, the first phase should be carried out with only the Engine 1 (98.1MW gas turbine unit) for the first nine years of the project economic life. This should followed by the second phase with engine 2 (30.2MW gas turbine unit) immediately while divesting Engine 1 afterwards. This approach has considerable economic benefits as it stand to reduce the carrying charges of the entire project.

The energy production cost outlook with and withiout optimsied option is discipted in Figure 6-10. The result shows a significant improvemet in cost of electricityt with optimization after the the first nine years because the capacity and thermal efficiencies associated with production history from ten years till the end of the project favours the use of the 30.2 MW.

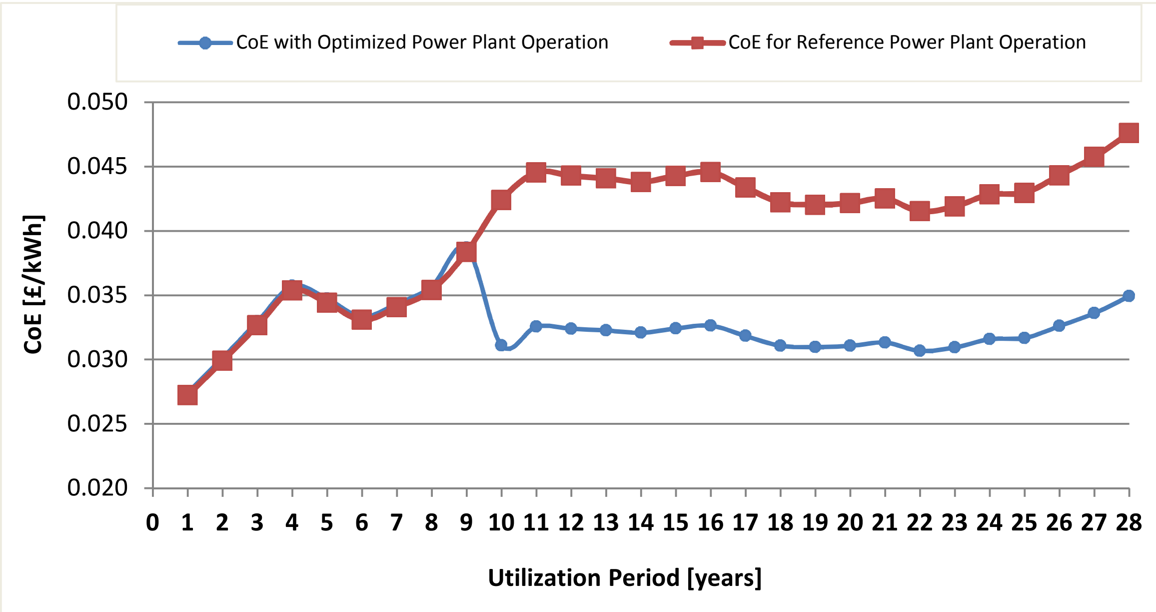


Figure 6-10: Cost of Electricity with and without Optimization of Power Plant Operations

6.6 Power Plant GT Unit Divestment Option Economic Result

The economic results following the power plant divestment operational options are shown in Figure 6-11for the deterministic value and Figure 6-12 for the probabilistic analysis based on the variation of specific TCI cost cases simulated. The results indicated an increase in economic performance outputs. Comparing the reference case with application of divestment method with the same range of uncertainty in total capital investment cost shows a far better improvement. For instance, the 90% NPV value between £25.20M and £97.43M in the reference case has seen increase between £ 55.30M and £ 98.74M. Similarly for the 77.7% probability of IRR changed from 19.4% -47.0% to 11.5% -29.1%; 80% probability of PBT initially between 1.3 and 5.8 years changed to 1 and 4.6 years. These results are further made clearer in Figures 6-13 and 6-14 below for both deterministic and probabilistic terms respectively. The implication of this result can be seen as not only improving the economic output performance but reducing the economic risk alike. This can be quantified using the differences between these values.

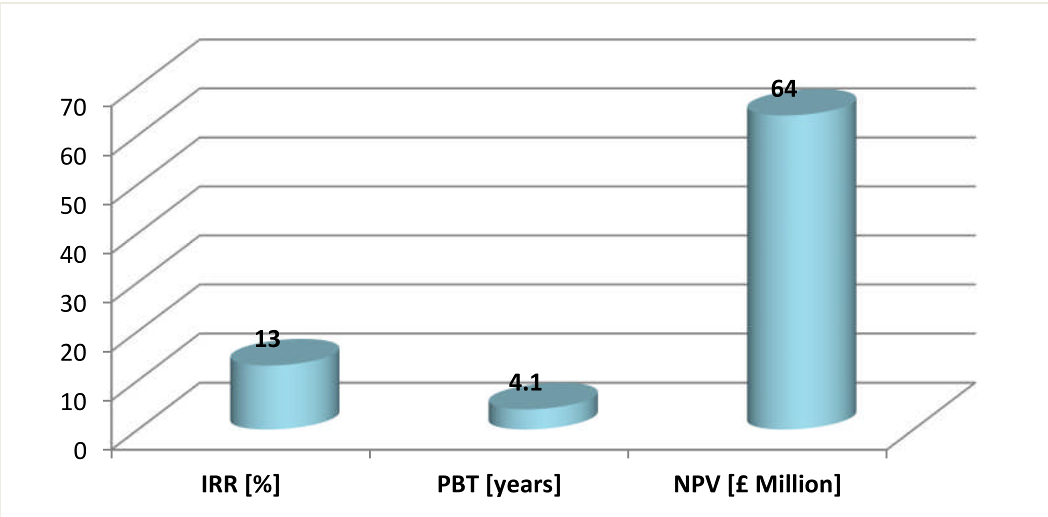
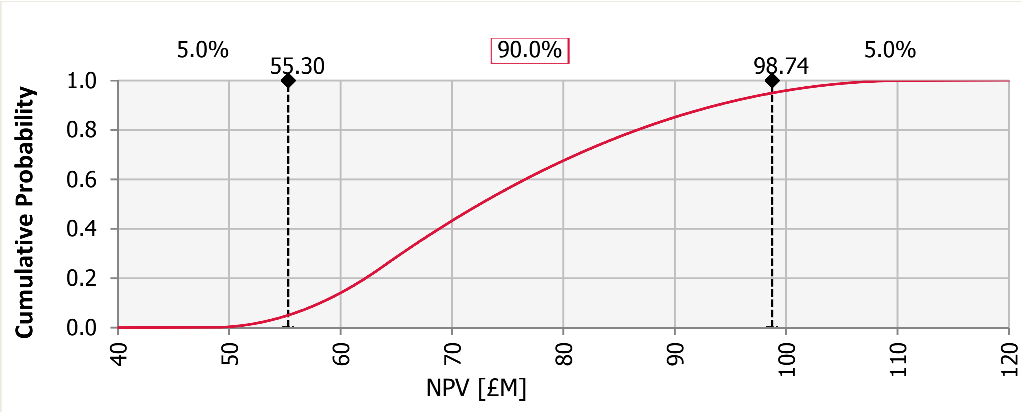
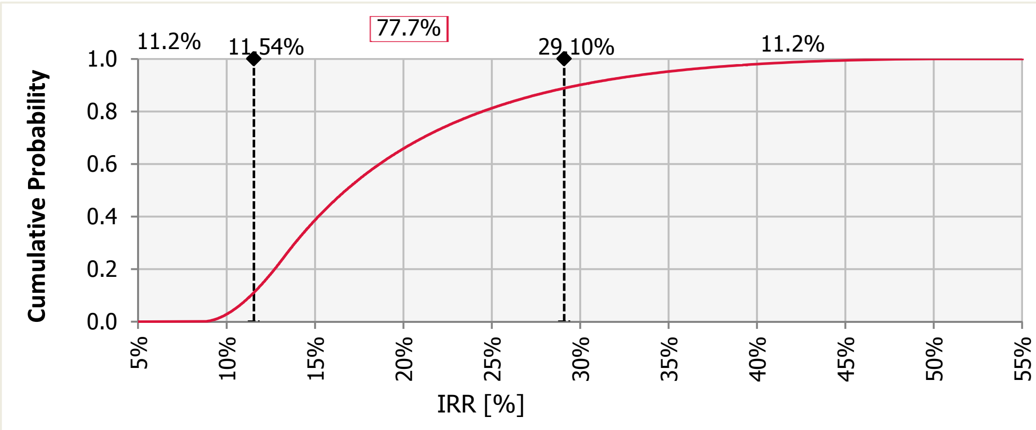


Figure 6-11: Deterministic Economic Appraisal Result with Divestment Operation



(a)



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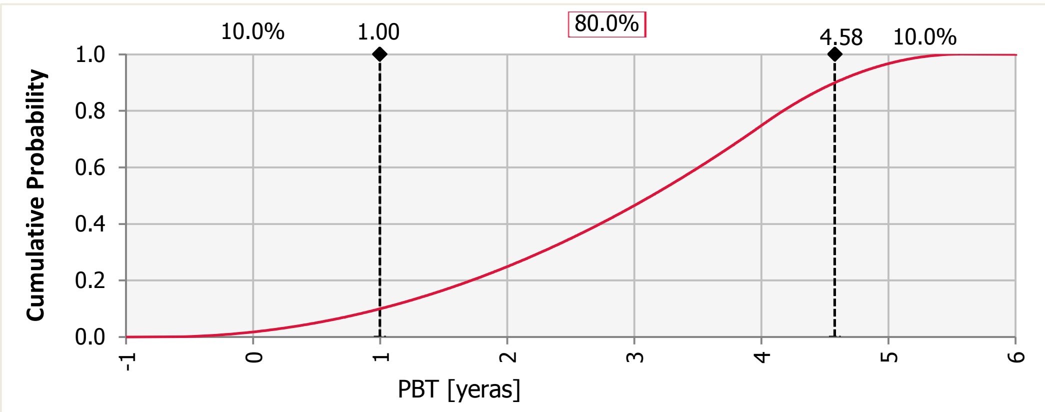


(c)

Figure 6-12: Probabilistic Economic Appraisal Result with Divestment Operation: (a) NPV, (b) IRR and (c) PBT

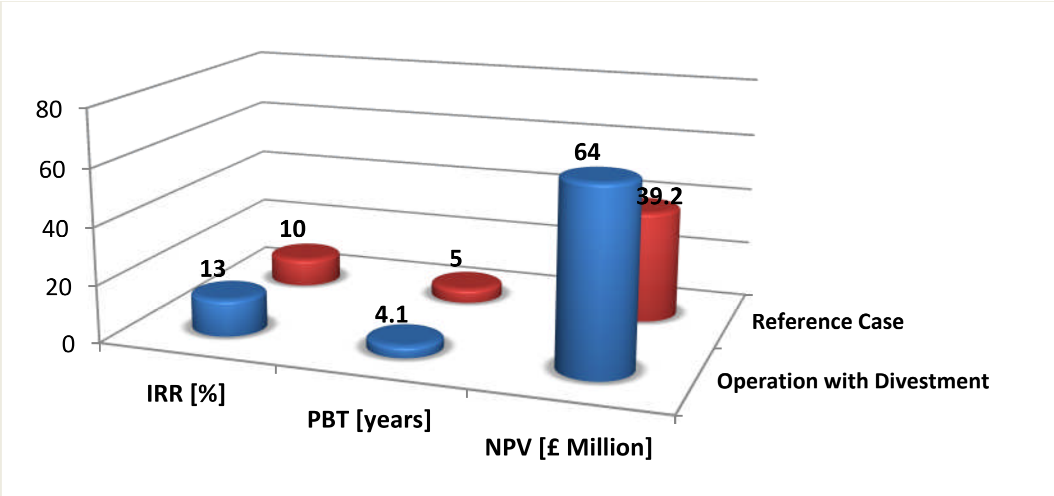


Figure 6-13: Comparison of Power Plant Operations with and without GT Divestment

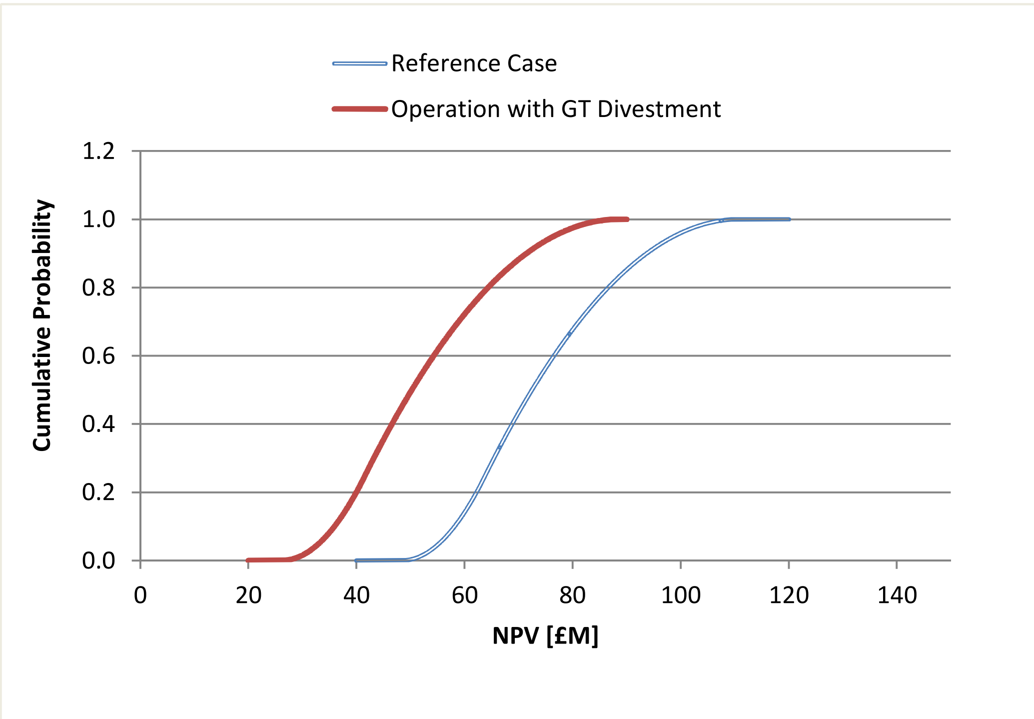


Figure 6-14: Comparison of Power Plant Operations with and without GT Divestment

6.7 Power Plant Makeup-Fuel Operation Economic Result

The economic performance result of the power plant makeup-fuel operation shows an improvement compared to reference case and power plant divestment in terms of IRR and PBT Figures 16-15 6-16 and 6-17 below. One of the important result from optimization indicated that makeup-fuel option has the ability of using only one unit of the 98.1MW gas turbine, thereby reducing the total capital cost of the pant.

Unfortunately the power plant makeup-fuel operation alternative for this case study will require about 120 Bcf of extra gas reserve to maintain the engine at full-load for the whole utilization economic life of 28 years. This is more than one and half times greater than the associated gas produced in within the 28 years period. Depending on availability of fuel supply to satisfy the required makeup volume, different gas turbine unit combination option is possible.

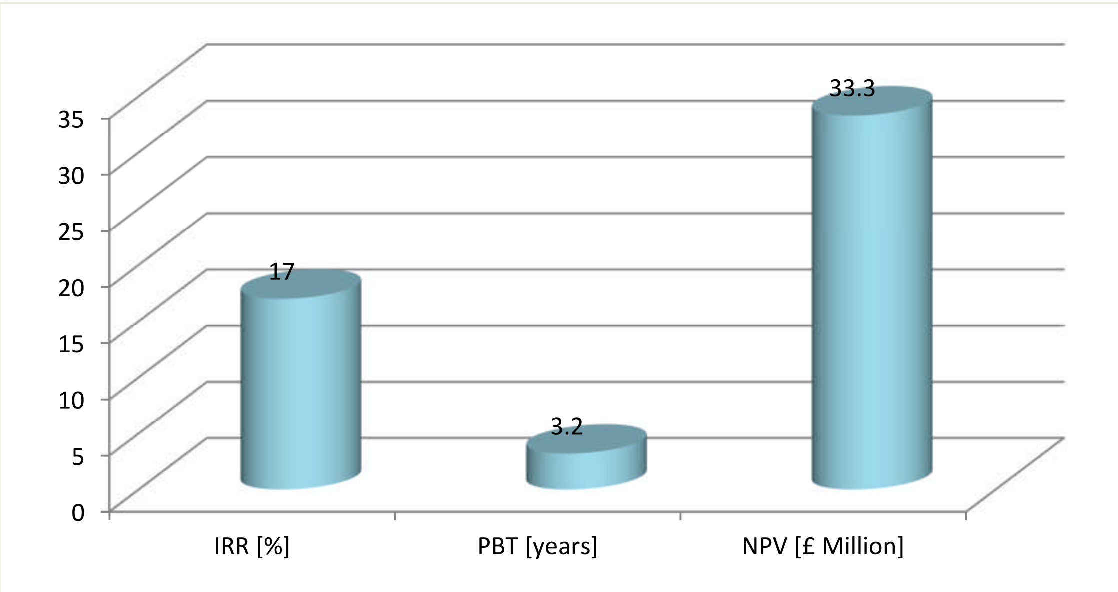
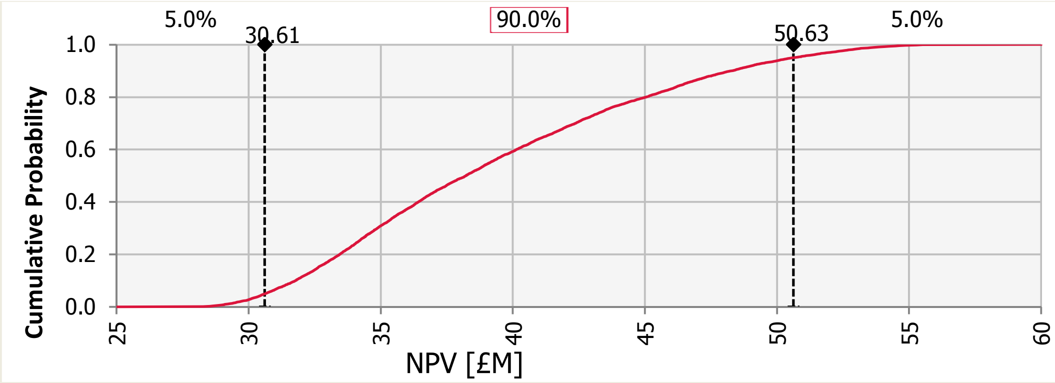
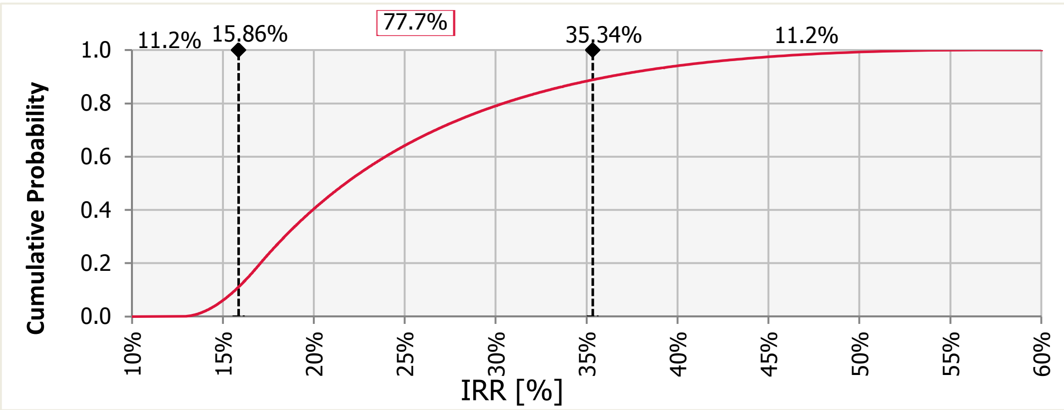


Figure 6-15: Deterministic Economic Appraisal Result with Divestment Operation



(a)



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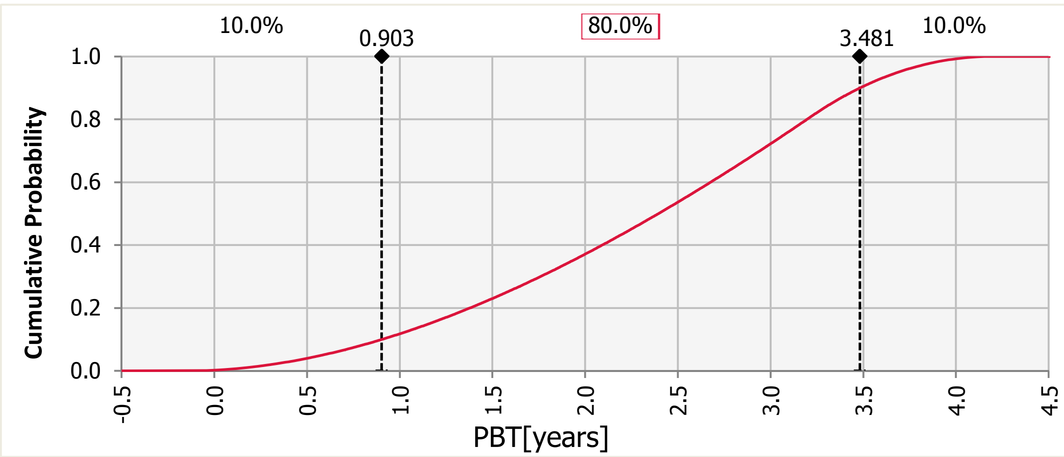

(c)

Figure 6-16: Probabilistic Economic Appraisal Result with Divestment Operation: (a) NPV, (b) IRR and (c) PBT

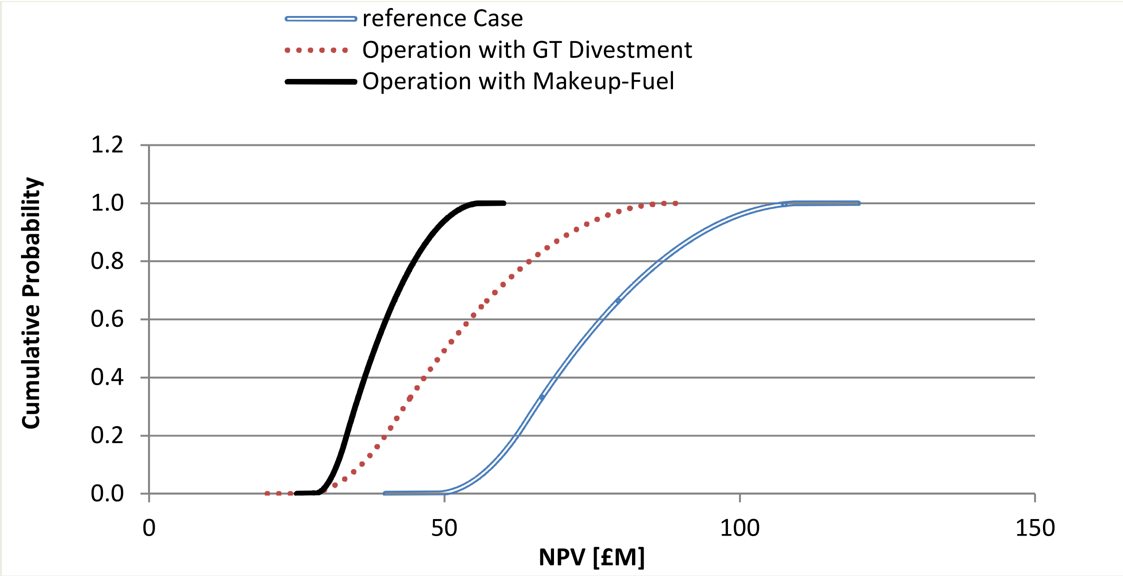

Figure 6-17: NPV Comparison of Power Plant Operations with Reference Case

In some scenario the required makeup-fuel for full-load operation may not be achievable. Therefore, there is need to reassess the economic performance output of power plant makeup-fuel operation alternative against different levels of available makeup-fuel streams and their cost. Variation in NPV with different makeup-fuel throughput availability and price is depicted in Figure 6-18. Apparently, increasing makeup-fuel price and decreasing makeup-fuel throughput both decreases the viability of power plant makeup-fuel operation. The combined impact of this two parameters will introduce more risk for the makeup-fuel option thereby putting the GT unit divestment option in a more technical and economic attractive position. More to this option is the erratic nature of makeup-fuel supply demand Figure 6-19 below.

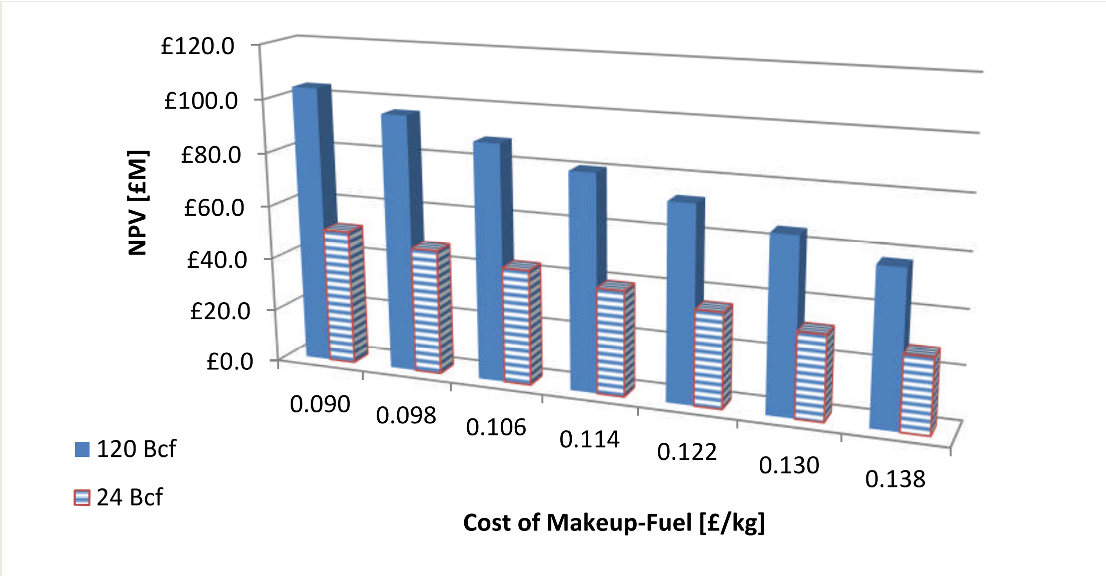

Figure 6-18: The NPV of Makeup-Fuel Power Plant Operation vs. Change in Fuel Throughput availability and Price

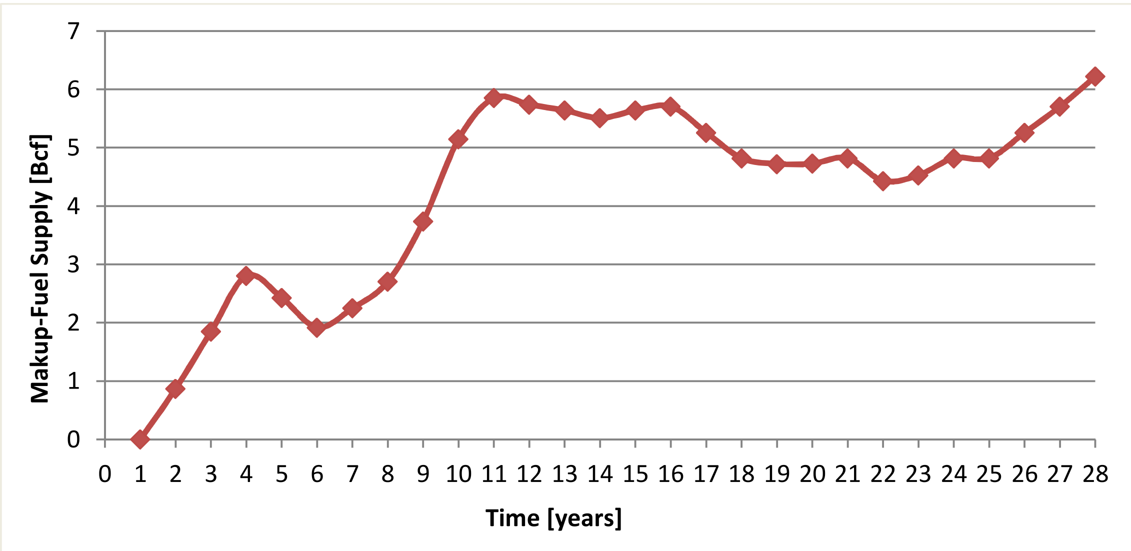

Figure 6-19: Makeup-Fuel Supply Schedule

Chapter 7

Conclusions and Recommendation

7.1 Conclusions

This thesis has described a research contributions to the development of using gas turbines for associated gas utilization which aims to harness a quality energy source wasted to flaring during most oil production for onsite power generation (gas-to-wire, GTW). The GTW predictive tool has been developed to evaluate the investment in new power plant. The developed GTW framework has capability of assessing the changes in associated gas production profile caused by production decline and its implications on the power plant output performance. This is an important facet divulged at the course of this work leading to power plant operational alternatives during decline regime to include gas turbine unit divestment and makeup-fuel options capable of improving the overall performance of GTW scheme.

A total of eight gas turbine engines both industrial and aeroderivative in the power range of 5.3MW to 200.6MW with some having advanced and regenerative cycles were modelled and simulated with pure natural gas and associated gas. These engines served as engine library for different capacities of the combustion turbine power plant as modelled in this study.

Thermodynamic performances of these engines with pure natural gas and a particular associated gas composition from Niger Delta region of Nigeria used for this study were compared. The pure natural gas for this study had a heating value of 49.736 MJ/kg while the heating value of the associated gas based on its constituent species simulated with NASA chemical equilibrium with application (CEA) code gave 45.616 MJ/kg. The major gas turbine thermodynamic performance characteristics of both fuels showed similar performance with only slight increase in fuel flow between 7.6% and 9.0% across the eight gas turbine units with the associated gas fuel case.

To account for varieties in species of associated gas produced in different part of the globe in this evaluation, gas turbine units off design point simulation were carried out with fuel heating value as the operating handle. The decreasing associated gas heating value increases compressor surge, for a constant power output requirement. This can be attributed to the increased fuel flow which would increase the shaft power and eventually the compressor speed. Thus using gas turbine engine initially designed for certain natural gas heating values for low calorific associated gas utilization may require modification of gas turbine to accommodate the rapid increase fuel flow for high power settings.

The onsite Nigerian associated gas utilisation based on gas turbines and other parameters used in this study showed a promising result and a reasonable return on the investment. The engine performance with this sort of gas is stable when compared to routine or pipeline natural gas quality. The little increase in fuel flow during operation is insignificant considering the fact that associated gas is cheap, since this could have been otherwise flared attracting penalties to oil producer. However, what has been identified and believed to oppose major economic deterrent is the associated gas production decline. This yields lots of redundant gas turbine units and lowers capacity factor of GTW power plant. Having said this, there could also be performance deterioration issue when impurities are engulfed depending on the associated gas quality and level of gas processing in place. Uniformly increasing associated gas production increase the GTW investment returns. A typical ambient temperature of the Nigerian associated gas production site studied affected the performance of the gas turbine engines. The gas turbine with nominal output power of 98.1 MW has net power output between 91.8 - 87.6 MW and a second gas turbine engine with nominal power capacity of 30.2 MW under the same site ambient temperature profile has its output power between 25.2 - 17.5 MW.

The two power plant operation stratagems used for augmentation of production decline or erratic associated gas supply schedule improved power plant performance when compared to reference case (i.e. without any of these alternatives). To achieve power plant operation with gas turbine divestment option requires multiple combinations of gas turbine units. The makeup-fuel option on the hand will be less prone to multiple gas turbine units' arrangements but may require makeup-fuel throughput significantly greater than the associated gas throughput been utilised depending on the production profile. Increasing the makeup-fuel throughputs reduces the viability (economic performance) of onsite power generation for associated gas monetization. To certain extent when a particular scenario involves huge amount of makeup-fuel, gas turbine divestment power plant operation becomes the more economic attractive option.

Other option for managing production decline would be deploying gas storage facility on site. This option would lead to reduced part-load operation of the gas turbine units; minimise the number of engine being withdrawn and boost the capacity factor of the power plant which is been reduced by the initiation of production decline. Though this will not come without disadvantages, it will increase total capital investment cost as well as capital operating and maintenance. In addition, when space/weight is critical issue it will not worth paying much attention. Though for a case whereby a depleted oil reservoir can serve as storage sinks this option will be worthwhile and more attractive.

The initial field development plan (FDP) should incorporate associated gas utilization scheme. GTW utilization of associated gas evaluation of given oil filed requires predictions of associated gas production profile. The power plant capital investment risk is a function of specific site and risk analysis should be extended to include oil production disruption from economic collapse due to oil price drop and sabotage disturbances.

Increasing the number of engines in the library will improve gas turbines engine unit combinations and accuracy of their selection to follow associated gas production profiles.

7.1 Recommendation for Further Work

The following areas will be promising for further research to increase the accuracy and benefits of GTW associated gas utilization scheme:

- Assessment of degradation of hot path section of the gas turbine engine for typical associated gas contaminant.

- Assessment of emission level with different associated gas composition under part-load operation regime dictated by production decline.

- A detailed cost of makeup-fuel including analysis, modelling and techno-economic analysis of pipeline as maybe required.

- Associated gas utilization for combined heat and power generation to heating and enhanced oil recovery.

- Integration of bulk electricity transmission model for different power plant operation scenarios.

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APPENDICES

Appendix A

Natural Transportation Modes

Gas to Wire

Gas to wire technology (GTW) is a developing technology [28] for gas monetisation. Basically GTW is onsite power generation and transmission by high voltage cable usually by high voltage direct current (HVDC) transmission for long distance to minimise voltage drop and power losses. Generally GTW is proposed to monetise marginal gas when other conventional option like PNG and LNG are not economically and environmentally feasible [9]. Whereas power can be generated anywhere, still about 80% of natural gas is transported globally for power generation [121]; despite the difficulties in storing and transporting gas due to its physical nature - demanding high pressure and/or low temperature to raise it bulk density [10]. GTW could be sited onshore or offshore.

Advantages of GTW on Floating Production, Storage and Offloading (FPSO) platform application have been reported [25]. These advantages were seen when compared with other monetisation options as follows: (i) technically, LNG and GTL will require a great deal of adaption to counter vessel motion; unlike power generation and CNG both has proven technology in floating applications, and (ii) compared with pipeline, subsea cable transmission is less sensitive to water depth and economically feasible for distance around 150 to 400 km with a capacity of 500 MW. An offshore GTW technology using floating combined cycle power plant (Sevan GTW) shown in Figure A 1 below has been proposed by Sevan Marine Norway [122]. The CO2 from the feed gas will be captured and injected into the subsea gas reservoirs for efficient carbon management. SBM Offshore Group is considering both import/export of electrical power to and from FPSO's platforms [123]. The import of electric energy from shore to offshore production unit/customers (Wire to Wire) was anticipated to have several advantages like having more free space on offshore deck floaters (less weight on offshore structure) and less offshore maintenance saving on CAPEX/OPEX. Their floating power generating unit (FPGU) concept will generate up to 500MW for standalone unit and 150 MW in a unit comprising LNG and power. The FPGU will have on-board gas treatment plat, liquid storage and export, electric power export capability between 300- 500MW depending on vessel size.

Figure A 1: Proposed offshore Sevan GTW - Floating Gas Power plant [47]

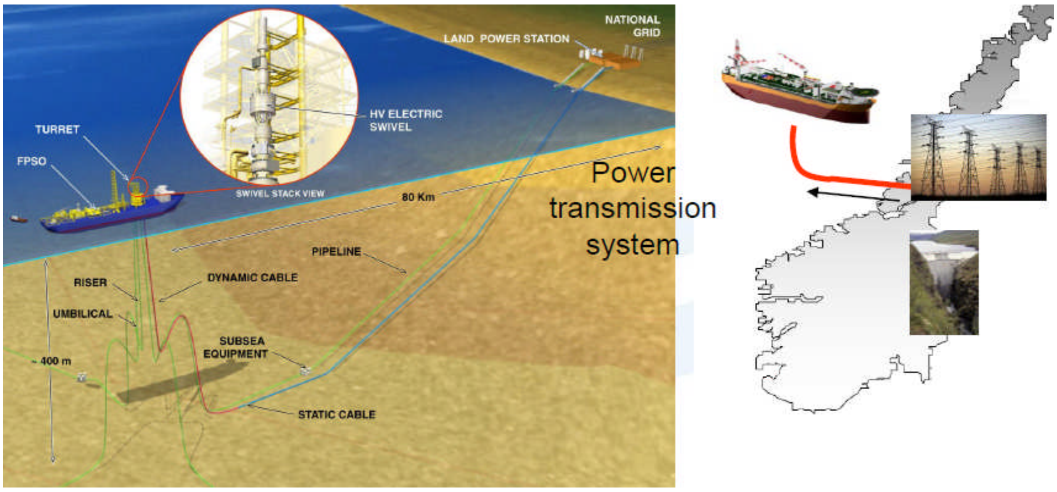


Figure A 2: Offshore Electric Energy Import (wire to wire) [48]

Similarly Toyohashi University in partnership with Hitachi and Arabian Oil/JGC [9, 124] has espoused a significant contribution to GTW technology for gas monetisation. Their model is shown in Figure A 3 below, which covers: (i) development of fuel pre-treatment plant (ii) development of gas-oil dual combustor for gas turbine, and (iii) studies on the hot path of the turbine system. However GTW is still mistaken for power transmission as many researchers focus and limit their gas monetisation comparison model between GTW and other gas monetisation methods by amount of electric energy transmitted.

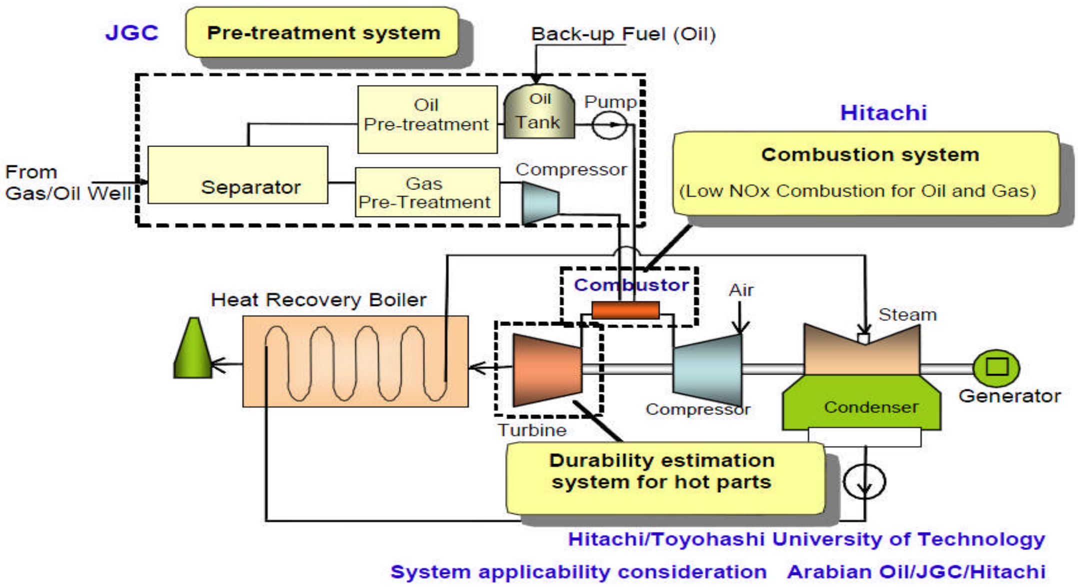


Figure A 3: Well-Site GTCC System [9, 124] and Research Interest

Liquefied Natural Gas

Liquefied natural gas (LNG) is a processed natural gas that has been cooled to a temperature of about -161 0C (-256 0F) at atmospheric pressure and condenses to a liquid. This process reduces the original volume of the gas at room temperature to about 600 times, thereby making it economical more attractive to transport over longer distance by special designed LNG vessel where transportation by pipeline is too expensive [121]. The LNG process chain involves different stages of specialised technological process to bring natural gas from the producing to consuming country. Initial stage involves gathering the gas from the reserves to the processing and liquefaction plant for liquefaction. This is followed by storing and loading of the product in LNG vessel for shipping to a designated country/customer. Final stage of this process will involve offloading/storing and de-gasification of LNG in a gasification facility to be distributed by pipeline as gas again to local consumers. Improvement in thermodynamic efficiencies of LNG facility has lowered the cost of LNG plant over the last three decades, making LNG the major gas export choice worldwide with an approximated 15 billion scf transported in day [19]. LNG infrastructure involves huge capital investment (up to US$ 1 billion capital investment for a train to produce about 500 million scf/d of gas) and long contract over 20 years and require large proven gas reserves (more than 3 Tscf) [125].

Figure A 4: LNG Value Chain [44]

Compressed Natural Gas

Compressed natural gas (CNG) is evolving technology for transportation of natural gas by compressing the volume under pressure and transporting it in specially designed containers. Stening et al. [126] developed a Coselle^{TM} CNG technology based on coiled pipe technique called coselle pressure vessel. They divulge that their CNG carrier will be more economical than LNG for shipping gas over short sea route. Figure A 5 and Figure A 6 shown below give basic data and a cross-section of the coselle respectively for their studies. Other CNG technologies were the VotransTM technology developed by Enerseas, GTM technology by TransCanada, CRPV Technology by Trans Ocean gas, and Pressurised natural gas vessel technology by Knusten OAS.

Coselle		
Outside diameter	50.0	feet
Inside diameter	10.0	feet
Height	11.25	feet
Total weight	445	tonnes
Pipe		
Pipe OD	6.625	inches
Pipe wall	0.25	inches
Pipe length	9.9	miles
Gas (GHV = 1080 Btu/scf)		
Gas pressure	3000	psi
Gas temperature	30	deg. F
Total gas weight	71	tonnes
Sales gas capacity	3.09	mmcf

Figure A 5: Coselle Data [126]

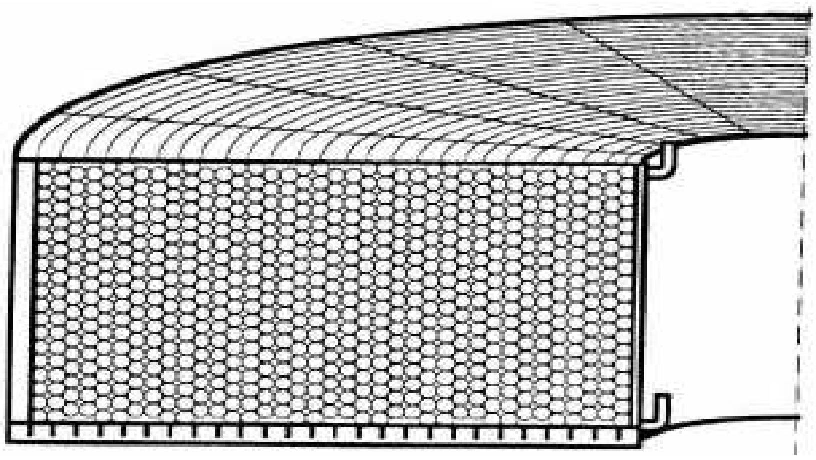


Figure A 6 Coselle Section [126]

Pipelined Natural Gas

Pipeline is a matured technological means of transporting gas to the customers both continental and local. Natural gas could be transported via underground/above ground and subsea pipelines. The major component of the gas pipeline system is the pipelines, compressor station and other facilities for storing, monitoring and safety gadgets. Pipeline systems are used in gas gathering, gas transmission and distribution to local customers. Economics of pipeline is influenced by pipe diameter, terrain/distance to market, operating pressure, and rights of way among others. However operating cost of pipeline varies a lot according to the number of installed compression station. Pipeline system is less complex than LNG system [49], and cost reduction is rare except those done during project design and construction phase, and those due to inspection activities brought by recent competition among the inspection companies. There has been a remarkable development in subsea pipeline systems; however, an offshore pipeline has problems of condensate and hydrate formation leading to pipeline blockage [127].

Natural Gas Hydrates/Gas-To-Solid

Natural gas hydrates (NGH) is made up of physical combination of water and natural gas in crystalline solid form with individual gas molecules existing in cages of water molecules [127]. The production of NGH has been achieved in the laboratory and involves two main stages via bulk separation—primary stage and dewatering unit to complete the process—second stage. NGH contains about 150-180 Sm3 of natural gas per m3 of solid depending of the pressure and temperature, a factor which makes the economics of NHG storage and transportation interesting especially when refrigerated at low enough temperature and atmospheric pressure [4].

Gas-to-Liquid, GTL

Gas-to-liquid gas monetisation technology is a process of conversion and transportation of natural gas into a liquid hydrocarbon. This process involves conversion of natural into synthetic gas (syngas)—a mixture of carbon monoxide and hydrogen and subsequent catalytic conversion of the syngas into hydrocarbons [127].

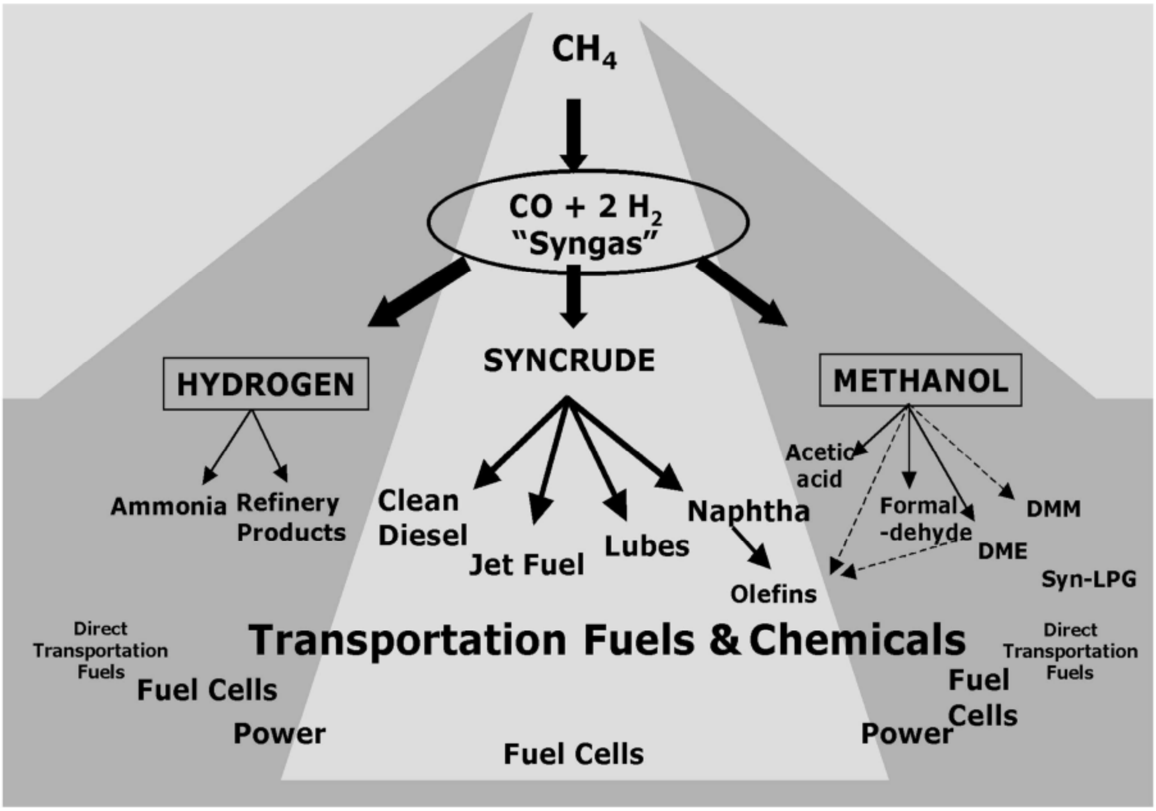


Figure A 7: GTL Option [128]

Appendix B

Fuel Composition, NASA CEA and GTs TURBOMATCH Input Files

Fuel composition

Table B 1: Composition of Associated Gas Variant from used for this Study

Composition	***Mole Fraction***
Water	0.26
Nitrogen	0.61
Carbon Dioxide	2.59
Hydrogen Sulphide	0.001
Methane	78.81
Ethane	10.46
Propane	4.62
Iso-butane	0.79
N-Butane	0.97
Iso-pentane	0.31
N-Pentane	0.27
N-Hexane	0.21
N-Heptane	0.10

Associated Gas Input File for Gas Turbine Simulation

```
!

!
!  This input file for CEA creates gas property tables for NAOCAPGNigeria
!
!    H2O                0.2315% Mass
!    N2                 0.8447% Mass
!    CO2                5.635% Mass
!    CH4                62.5% Mass
!    C2H6               15.55% Mass
!    C3H8               10.07% Mass
!    C4H10,isobutane    5.172% Mass
!
!   -------
!   Dry Air
!   -------
reac
  name N2    wtfrac=0.755184,
  name O2    wtfrac=0.231416,
  name Ar    wtfrac=0.012916,
  name CO2   wtfrac=0.000484691,
!
!   fuel-air-ratio = 0
!   ------------------
  name H2O  wtfrac= 0.0000001  t(k)=298.15
  name N2  wtfrac= 0.0000001  t(k)=298.15
  name CO2  wtfrac= 0.0000001  t(k)=298.15
  name CH4  wtfrac= 0.0000001  t(k)=298.15
  name C2H6  wtfrac= 0.0000001  t(k)=298.15
```

```
  name C3H8  wtfrac= 0.0000001  t(k)=298.15
  name C4H10,isobutane  wtfrac= 0.0000001  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
!
!   --------------------------
!   Dry Air + Combustion Gases
!   --------------------------
reac
  name N2    wtfrac=0.715814,
  name O2    wtfrac=0.219351,
  name Ar    wtfrac=0.0122426,
  name CO2   wtfrac=0.000459423,
!
!   fuel-air-ratio = 0.055
!   ---------------------
  name H2O  wtfrac= 0.00012071  t(k)=298.15
  name N2  wtfrac= 0.000440378  t(k)=298.15
  name CO2  wtfrac= 0.00293749  t(k)=298.15
  name CH4  wtfrac= 0.0325824  t(k)=298.15
  name C2H6  wtfrac= 0.00810551  t(k)=298.15
  name C3H8  wtfrac= 0.00525009  t(k)=298.15
```

```
  name C4H10,isobutane  wtfrac= 0.00269615  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
!
!   -----------------
!   Wet Air, war=0.03
!   -----------------
reac
  name N2    wtfrac=0.733188,
  name O2    wtfrac=0.224675,
  name Ar    wtfrac=0.0125398,
  name CO2   wtfrac=0.000470574,
  name H2O   wtfrac=0.029126,
!
!   fuel-air-ratio = 0
!   ------------------
  name H2O  wtfrac= 0.0000001  t(k)=298.15
  name N2  wtfrac= 0.0000001  t(k)=298.15
  name CO2  wtfrac= 0.0000001  t(k)=298.15
  name CH4  wtfrac= 0.0000001  t(k)=298.15
  name C2H6  wtfrac= 0.0000001  t(k)=298.15
  name C3H8  wtfrac= 0.0000001  t(k)=298.15
```

```
  name C4H10,isobutane  wtfrac= 0.0000001  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
!
!   ------------------------------------
!   Wet Air, war=0.03 + Combustion Gases
!   ------------------------------------
reac
  name N2    wtfrac=0.696022,
  name O2    wtfrac=0.213286,
  name Ar    wtfrac=0.0119041,
  name CO2   wtfrac=0.00044672,
  name H2O   wtfrac=0.0276496,
!
!   fuel-air-ratio = 0.055
!   -------------------
  name H2O  wtfrac= 0.000117373  t(k)=298.15
  name N2  wtfrac= 0.000428201  t(k)=298.15
  name CO2  wtfrac= 0.00285626  t(k)=298.15
  name CH4  wtfrac= 0.0316815  t(k)=298.15
  name C2H6  wtfrac= 0.00788139  t(k)=298.15
  name C3H8  wtfrac= 0.00510493  t(k)=298.15
```

```
  name C4H10,isobutane  wtfrac= 0.0026216  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
!
!   -----------------
!   Wet Air, war=0.1
!   -----------------
reac
  name N2    wtfrac=0.686531,
  name O2    wtfrac=0.210378,
  name Ar    wtfrac=0.0117418,
  name CO2   wtfrac=0.000440628,
  name H2O   wtfrac=0.0909091,
!
!   fuel-air-ratio = 0
!   ------------------
  name H2O  wtfrac= 0.0000001  t(k)=298.15
  name N2  wtfrac= 0.0000001  t(k)=298.15
  name CO2  wtfrac= 0.0000001  t(k)=298.15
  name CH4  wtfrac= 0.0000001  t(k)=298.15
  name C2H6  wtfrac= 0.0000001  t(k)=298.15
  name C3H8  wtfrac= 0.0000001  t(k)=298.15
```

```
  name C4H10,isobutane  wtfrac= 0.0000001  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
!
!   ------------------------------------
!   Wet Air, war=0.1 + Combustion Gases
!   ------------------------------------
reac
  name N2    wtfrac=0.653839,
  name O2    wtfrac=0.20036,
  name Ar    wtfrac=0.0111827,
  name CO2   wtfrac=0.000419646,
  name H2O   wtfrac=0.0865801,
!
!   fuel-air-ratio = 0.055
!   --------------------
  name H2O  wtfrac= 0.000110259  t(k)=298.15
  name N2  wtfrac= 0.00040225  t(k)=298.15
  name CO2  wtfrac= 0.00268316  t(k)=298.15
  name CH4  wtfrac= 0.0297614  t(k)=298.15
  name C2H6  wtfrac= 0.00740373  t(k)=298.15
  name C3H8  wtfrac= 0.00479554  t(k)=298.15
```

```
  name C4H10,isobutane  wtfrac= 0.00246272  t(k)=298.15
!
problem case=NAOCAPGNigeria
  tp p(bar)=100,
     t(k)= 200, 300, 400, 500, 600, 700, 800, 900,1000,1100,
          1200,1300,1400,1500,1600,1700,1800,1900,2000,2100,
          2200,2300,2400,2500,2600
output siunits trace=5.e-6
short
plot t gam cp mw h s
only Ar  CO2  H2O  N2  O2
end
```

GTs Turbomatch and Gas Turb Input Files

Engine 1

```
! 200MW RANGE INDUSTRIAL GAS TURBINE SIMULATION

MODELLED BY NNAMDI ANOSIKE,  2011////

OD SI KE VA XP
-1
-1
INTAKE  S1-2     D1-4             R180
COMPRE  S2-3     D5-11            R182     V5  V6

PREMAS  S3,4,10  D12-15

BURNER  S4-5     D16-18           R184

MIXEES  S5,10,6

TURBIN  S6-7     D19-26,182,27            V19 V20

NOZCON  S7-8,1   D28              R107

PERFOR  S1,0,0   D19,29-31,107,180,184,0,0,0,0,0,0,0

CODEND

DATA ITEMS////

!INTAKE

1 0.0            ! INTAKE ALTITUDE

2 0.0            ! ISA DEVIATION

3 0.0            ! MACH NO

4 0.9951         ! PRESSURE RECOVERY

!COMPRESSOR
```

```
5 -1.0          ! Z PARAMETER
6 -1.0          ! ROTATIONAL SPEED N
7 15.5          ! PRESSURE RATIO
8 0.89          ! ISENTROPIC EFFICIENCY
9 1.0           ! ERROR SELECTION
10 3.0          ! MAP NUMBER
11 0.0          ! ANGLE
!PREMAS
12 0.93         ! BLEED AIR
13 0.0          ! FLOW LOSS: DELTA (W)
14 1.0          ! PRESSURE RECOVERY
15 0.0          ! PRESSURE DROP
!BURNER
16 0.05         ! FRACTIONAL PRESSURE LOSS DP/P
17 0.998        ! COMBUSTION EFFICIENCY
18 -1.0         ! FUEL FLOW
!TURBINE
19 200000000.0   ! AUXILIARY WORK
20 -1.0         ! NDMF
21 0.6          ! NDSPEED CN
22 0.895        ! ISENTROPIC EFFICIENCY
23 -1.0         ! PCN
```

```
24 1.0          ! COMPRESSOR NUMBER
25 3.0          ! TURBINE MAP NUMBER
26 1000          ! POWER LOW INDEX
27 0.0          ! NGV ANGLE RELATIVE TO D.
!NOZCON
28 -1.0          ! THROAT AREA
!PERFOR
29 1.00          ! PROPELLER EFFICIENCY
30 0.0          ! SCALING INDEX
31 0.0          ! REQUIRED THRUST
-1
1 2 470.0          ! INLET MASS FLOW
5 6 1600.0          ! COMBUSTION OUTLET TEMPERATURE
-1
-3
```

Engine 2

```
! 100MW RANGE  INDUSTRIAL GAS TURBINE SIMULATION

INTERCOOLED THREE SHAFT AERODERIVATIVE ENGINE

MODELLED BY NNAMDI ANOSIKE,  2011////

OD SI KE VA XP

-1
-1
INTAKE S1-2          D1-4      R100

COMPRE S2-3          D5-11     R101    V5 V6

DUCTER S3-4          D12-15    R102

COMPRE S4-5          D16-22    R103    V16 V17

PREMAS S5,6,16       D23-26

PREMAS S16,17,18  D27-30

BURNER S6-7          D31-33    R104

MIXEES S17,7,8

TURBIN S8-9          D34-41,103        V35

DUCTER S9-10         D42-45

MIXEES S10,18,11

TURBIN S11-12        D46-53,101        V47

TURBIN S12-13        D54-61            V54 V55

DUCTER S13-14        D62-65

NOZCON S14-15,1   D66      R105

PERFOR S1,0,0 D54,67-69,105,100,104,0,0,0,0,0,0
```

```
CODEND

DATA ITEMS////
!INTAKE
1 0.0        !INTAKE ALTITUDE
2 0.0        !ISA DEVIATION
3 0.0         !MACH NO
4 0.9951       !PRESSURE RECOVERY
!LP COMPRESSOR
5 0.85        !SURGE MARGIN (DEFAULT=0.85)
6 1.0         !SPOOL SPEED (DEFAULT=1.0)
7 3.0         !PRESSURE RATIO
8 0.89        !ISENTROPIC EFFICIENCY
9 0.0          !ERROR SELECTION
10 4.0        !COMPRESSOR MAP NUMBER
11 0.0        !ANGLE
!DUCTER
12 2.0          !INTERCOOLING
13 0.03         !PRESSURE LOSS
14 0.60         !EFFICIENCY
15 100000.00   !LIMITING VALUE OF FUEL FLOW
!HP COMPRESSOR
```

```
16 0.85       !SURGE MARGIN (DEFAULT=0.85)

17 1.0        !SPOOL SPEED (DEFAULT=1.0)

18 14.0       !PRESSURE RATIO

19 0.89       !ISENTROPIC EFFICIENCY

20 1.0        !ERROR SELECTION

21 3.0        !COMPRESSOR MAP NUMBER

22 0.0 !     ANGLE

!TURBINE COOLING 1

23 0.90      !BLEED AIR

24 0.0      !FLOW LOSS

25 1.0      !PRESSURE RECOVERY

26 0.0     !PRESSURE LOSS

!TURBINE COOLING 2

27 0.70    !BLEED AIR

28 0.0      !FLOW LOSS

29 1.0      !PRESSURE RECOVERY

30 0.0       !PRESSURE LOSS

!BURNER

31 0.065   !PRESSURE LOSS

32 0.998   !COMBUSTION EFFICIENCY

33 -1.0    !FUEL FLOW

!HP TURBINE
```

34 0.0 !AUXILIARY POWER REQUIRED

35 0.8 !NON-DIMENSIONAL MASSFLOW (DEFAULT=0.8)

36 0.6 !NON-DIMENSIONAL SPEED (DEFAULT=0.6)

37 0.87 !ISENTROPIC EFFICIENCY

38 -1.0 !COMPRESSOR TURBINE

39 2.0 !COMPRESSOR NUMBER

40 1.0 !TURBINE MAP NUMBER

41 3.0 !POWER LAW INDEX

!DUCTER

42 0.0 !NO INTERCOOLING

43 0.0 !PRESSURE LOSS

44 0.0 !EFFICIENCY

45 0.0 !LIMITING VALUE OF FUEL FLOW

!IP TURBINE

46 0.0 !AUXILIARY POWER REQUIRED

47 0.8 !NON-DIMENSIONAL MASSFLOW (DEFAULT=0.8)

48 0.6 !NON-DIMENSIONAL SPEED (DEFAULT=0.6)

49 0.87 !ISENTROPIC EFFICIENCY

50 -1.0 !COMPRESSOR TURBINE

51 1.0 !COMPRESSOR NUMBER

52 3.0 !TURBINE MAP NUMBER

53 3.0 !POWER LAW INDEX

```
!POWER TURBINE
54 100000000.00 !AUXILIARY POWER REQUIRED
55 -1.0      !NON-DIMENSIONAL MASS FLOW (DEFAULT=0.8)
56 0.6     !NON-DIMENSIONAL SPEED (DEFAULT=0.6)
57 0.89    !ISENTROPIC EFFICIENCY
58  1.0     !RELATIVE ROTATIONAL
59 0.0      !COMPRESSOR NUMBER
60 3.0       !TURBINE MAP NUMBER
61 -1.0  !POWER LAW INDEX
62 0.0      !NGV ANGLE RELATIVE TO D.
!DUCTER
63 0.0      !NO INTERCOOLING
64 0.00     !PRESSURE LOSS
65 0.0       !EFFICIENCY
66 0.0       !LIMITING VALUE OF FUEL FLOW
!CONVERGENT NOZZLE
67 -1.0      !AIR FIXED
!PERFORMANCE
68 -1.0     !PROPELLER EFFICIENCY
69 0.0        !SCALING INDEX
70 0.0        !REQUIRED THRUST
-1
```

1 2 220.0 !INLET MASS FLOW

4 6 320 !INTERCOOLER OUTLET TEMPERATURE

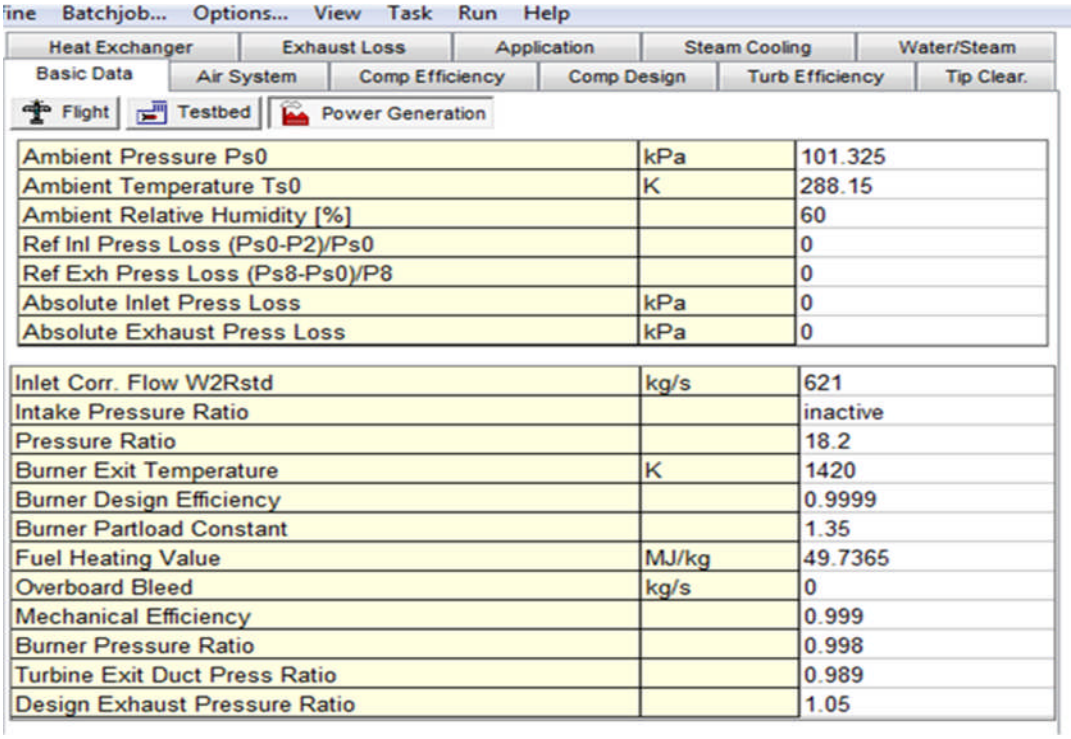
7 6 1600.0 !COMBUSTION OUTLET TEMPERATURE

-1

-3

Gas Turb Files

Engine 1



Ambient Pressure Ps0	kPa	101.325
Ambient Temperature Ts0	K	288.15
Ambient Relative Humidity [%]		60
Ref Inl Press Loss (Ps0-P2)/Ps0		0
Ref Exh Press Loss (Ps8-Ps0)/P8		0
Absolute Inlet Press Loss	kPa	0
Absolute Exhaust Press Loss	kPa	0

Inlet Corr. Flow W2Rstd	kg/s	621
Intake Pressure Ratio		inactive
Pressure Ratio		18.2
Burner Exit Temperature	K	1420
Burner Design Efficiency		0.9999
Burner Partload Constant		1.35
Fuel Heating Value	MJ/kg	49.7365
Overboard Bleed	kg/s	0
Mechanical Efficiency		0.999
Burner Pressure Ratio		0.998
Turbine Exit Duct Press Ratio		0.989
Design Exhaust Pressure Ratio		1.05

	W	T	P	WRstd		
Station	kg/s	K	kPa	kg/s	PWSD	= 202569.8 kW
amb		288.15	101.325			

1	619.810	288.15	101.325		PSFC = 0.1909 kg/(kW*h)
2	619.810	288.15	101.325	621.000	Heat Rate= 9495.8 kJ/(kW*h)
3	619.810	687.91	1844.115	52.720	Therm Eff= 0.3791
31	576.424	687.91	1844.115		WF = 10.74303 kg/s
4	587.167	1420.00	1840.427	72.379	
41	605.761	1399.73	1840.427	74.121	s NOx = 0.45143
49	605.761	774.48	107.575		incidence= 0.00000 °
5	624.355	772.02	107.575	970.473	XM8 = 0.2704
6	624.355	772.02	106.391		A8 = 9.2696 m²
8	624.355	772.02	106.391	981.267	P8/Ps8 = 1.05000
Bleed	6.198	687.91	1844.108		WBld/W2 = 0.01000

--- P2/P1 = 1.00000

Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies:	isentr	polytr	RNI	P/P	W_NGV/W2 = 0.03000
Compressor	0.8999	0.9309	1.000	18.200	WCL/W2 = 0.03000
Burner	0.9999			0.998	Loading = 100.00 %
Turbine	0.9000	0.8620	2.862	17.108	e45 th = 0.88816
Generator	1.0000				PW_gen = 202569.8 kW

Spool mech Eff 0.9990 Nom Spd 3600 rpm P6/P5 = 0.9890

----

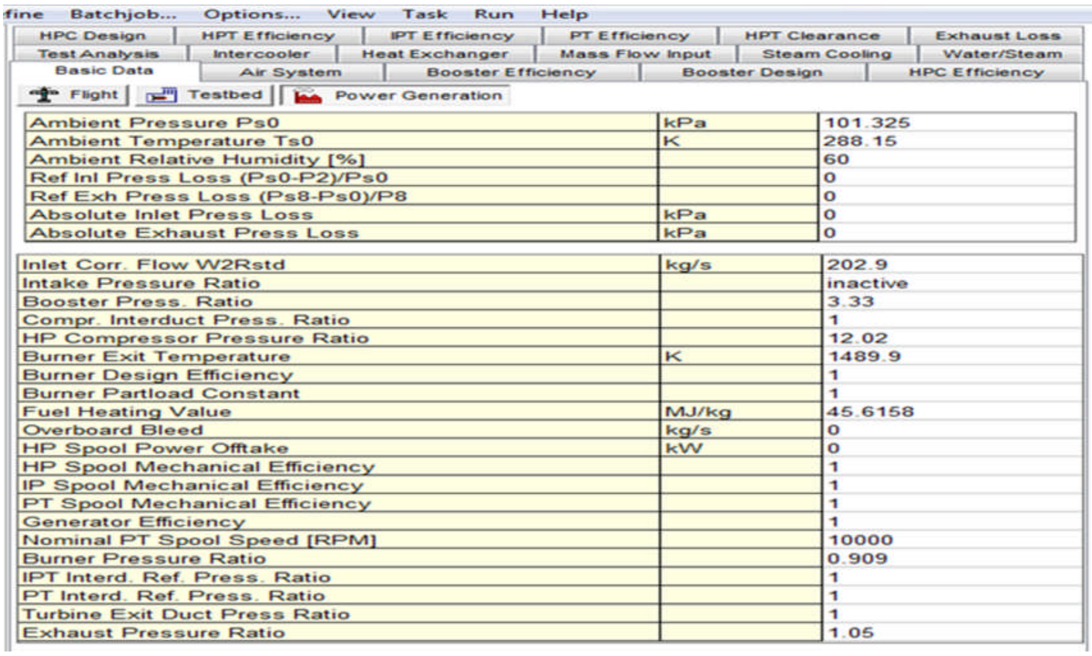
hum [%] war0 FHV Fuel

60.0 0.00637 49.736 Natural Gas

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\one spool 200MW range DP.C1S

__Engine 2__



fine Batchjob... Options... View Task Run Help

HPC Design | HPT Efficiency | IPT Efficiency | PT Efficiency | HPT Clearance | Exhaust Loss

Test Analysis | Intercooler | Heat Exchanger | Mass Flow Input | Steam Cooling | Water/Steam

Basic Data | Air System | Booster Efficiency | Booster Design | HPC Efficiency

Flight | Testbed | Power Generation

Ambient Pressure Ps0	kPa	101.325
Ambient Temperature Ts0	K	288.15
Ambient Relative Humidity [%]		60
Ref Inl Press Loss (Ps0-P2)/Ps0		0
Ref Exh Press Loss (Ps8-Ps0)/P8		0
Absolute Inlet Press Loss	kPa	0
Absolute Exhaust Press Loss	kPa	0

Inlet Corr. Flow W2Rstd	kg/s	202.9
Intake Pressure Ratio		inactive
Booster Press. Ratio		3.33
Compr. Interduct Press. Ratio		1
HP Compressor Pressure Ratio		12.02
Burner Exit Temperature	K	1489.9
Burner Design Efficiency		1
Burner Partload Constant		1
Fuel Heating Value	MJ/kg	45.6158
Overboard Bleed	kg/s	0
HP Spool Power Offtake	kW	0
HP Spool Mechanical Efficiency		1
IP Spool Mechanical Efficiency		1
PT Spool Mechanical Efficiency		1
Generator Efficiency		1
Nominal PT Spool Speed [RPM]		10000
Burner Pressure Ratio		0.909
IPT Interd. Ref. Press. Ratio		1
PT Interd. Ref. Press. Ratio		1
Turbine Exit Duct Press Ratio		1
Exhaust Pressure Ratio		1.05

Station W T P WRstd

Station kg/s K kPa kg/s PWSD = 98067.2 kW

amb 288.15 101.325

1 202.511 288.15 101.325 PSFC = 0.1740 kg/(kW*h)

2 202.511 288.15 101.325 202.900 P2/P1 = 1.00000

24 202.511 418.22 337.412 62.171 P25/P24 = 0.96000

25 202.511 300.00 323.916 64.762 P3/P2 = 38.42554

3 202.511 654.37 3893.467 7.957 Heat Rate= 7937.3 kJ/(kW*h)

31 202.511 654.37 3893.467 WF = 4.73999 kg/s

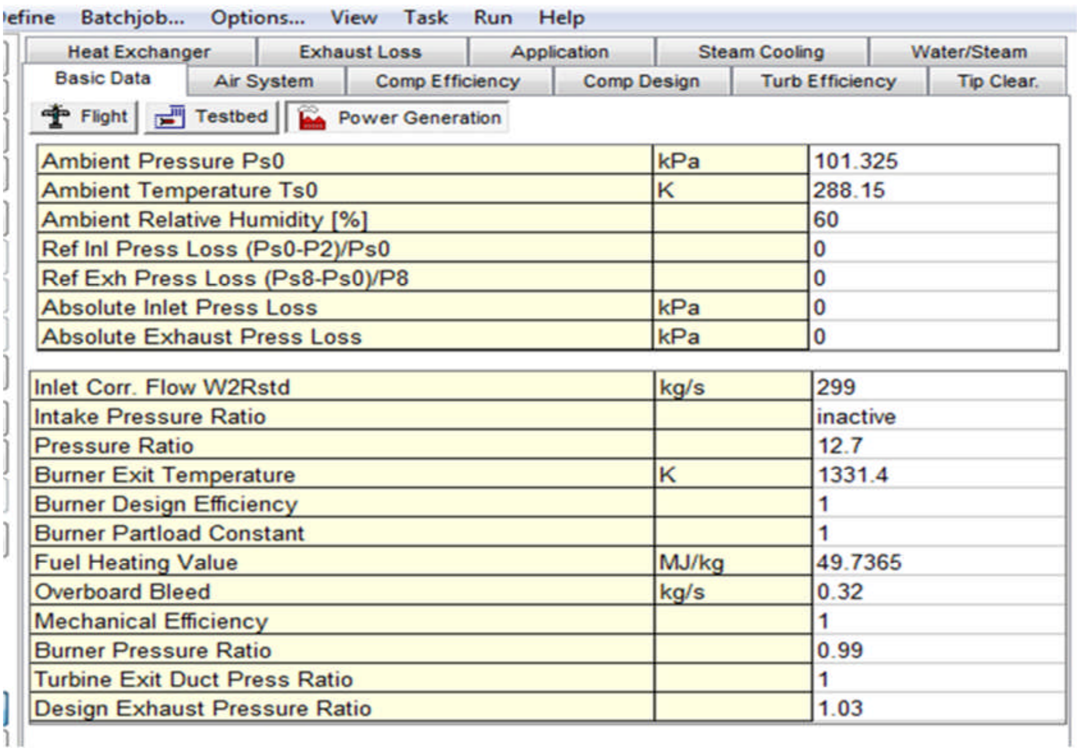
4 207.251 1489.90 3539.162 13.605 s NOx = 0.51224
41 207.251 1489.90 3539.162 13.605 Therm Eff= 0.45356
42 207.251 1207.97 1276.392 W_NGV/W25= 0.00000
43 207.251 1207.97 1276.392 WHcl/W25 = 0.00000
44 207.251 1207.97 1276.392 P44/P43 = 1.00000
45 207.251 1207.97 1276.392 33.967 WINcl/W25= 0.00000
46 207.251 1103.86 837.830 WIcl/W25 = 0.00000
47 207.251 1103.86 837.830 WLcl/W25 = 0.00000
48 207.251 1103.86 837.830 49.467 P48/P47 = 1.00000
49 207.251 703.91 106.391 Incidence= 0.00 °
5 207.251 703.91 106.391 311.076
6 207.251 703.91 106.391 311.076 P6/P5 = 1.00000
8 207.251 703.91 106.391 311.076 P8/Pamb = 1.05000
Bleed 0.000 654.37 3893.487 WBld/W2 = 0.00000
--- A8 = 2.93820 m²
Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa
Efficiencies: isentr polytr RNI P/P
Booster 0.9020 0.9169 1.000 3.330 WBHD/W2 = 0.00000
Compressor 0.8500 0.8911 2.051 12.020 WBld/W25 = 0.00000
Burner 1.0000 0.909 Loading = 100.00 %
HP Turbine 0.9051 0.8943 5.120 2.773 e442 th = 0.90510
IP Turbine 0.9126 0.9085 5.120 1.523 WlkLP/W25= 0.00000
LP Turbine 0.9057 0.8802 1.710 7.875 eta t-s = 0.88978
Generator 1.0000 PW_gen = 98067.2 kW

HP Spool mech Eff 1.0000 Nom Spd 12000 rpm TRQ = 100.00 %
IP Spool mech Eff 1.0000 Nom Spd 3600 rpm
LP Spool mech Eff 1.0000 Nom Spd 10000 rpm
----

hum [%]	war0	FHV	Fuel
60.0	0.00637	45.616	NAOCAPGNige

Input Data File:C:\Program Files (x86)\GasTurb\GasTurb11\100MW range DP parameter.CY3

Engine 3



Ambient Pressure Ps0	kPa	101.325
Ambient Temperature Ts0	K	288.15
Ambient Relative Humidity [%]		60
Ref Inl Press Loss (Ps0-P2)/Ps0		0
Ref Exh Press Loss (Ps8-Ps0)/P8		0
Absolute Inlet Press Loss	kPa	0
Absolute Exhaust Press Loss	kPa	0

Inlet Corr. Flow W2Rstd	kg/s	299
Intake Pressure Ratio		inactive
Pressure Ratio		12.7
Burner Exit Temperature	K	1331.4
Burner Design Efficiency		1
Burner Partload Constant		1
Fuel Heating Value	MJ/kg	49.7365
Overboard Bleed	kg/s	0.32
Mechanical Efficiency		1
Burner Pressure Ratio		0.99
Turbine Exit Duct Press Ratio		1
Design Exhaust Pressure Ratio		1.03

	W	T	P	WRstd		
Station	kg/s	K	kPa	kg/s	PWSD =	85110.5 kW
amb		288.15	101.325			
1	298.427	288.15	101.325		PSFC =	0.2218 kg/(kW*h)
2	298.427	288.15	101.325	299.000	Heat Rate=	11031.1 kJ/(kW*h)
3	298.427	624.80	1286.828	34.668	Therm Eff=	0.3264
31	298.107	624.80	1286.828		WF =	5.24352 kg/s

4 303.351 1331.40 1273.959 52.288

41 303.351 1331.40 1273.959 52.288 s NOx = 0.28255

49 303.351 818.21 104.365 incidence= 0.00000 °

5 303.351 818.21 104.365 500.363 XM8 = 0.2106

6 303.351 818.21 104.365 A8 = 5.9802 m²

8 303.351 818.21 104.365 500.363 P8/Ps8 = 1.03000

Bleed 0.320 624.80 1286.822 WBld/W2 = 0.00107

--- P2/P1 = 1.00000

Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies: isentr polytr RNI P/P W_NGV/W2 = 0.00000

Compressor 0.8900 0.9209 1.000 12.700 WCL/W2 = 0.00000

Burner 1.0000 0.990 Loading = 100.00 %

Turbine 0.8500 0.8047 2.098 12.207 e45 th = 0.85000

Generator 1.0000 PW_gen = 85110.5 kW

Spool mech Eff 1.0000 Nom Spd 3600 rpm P6/P5 = 1.0000

----

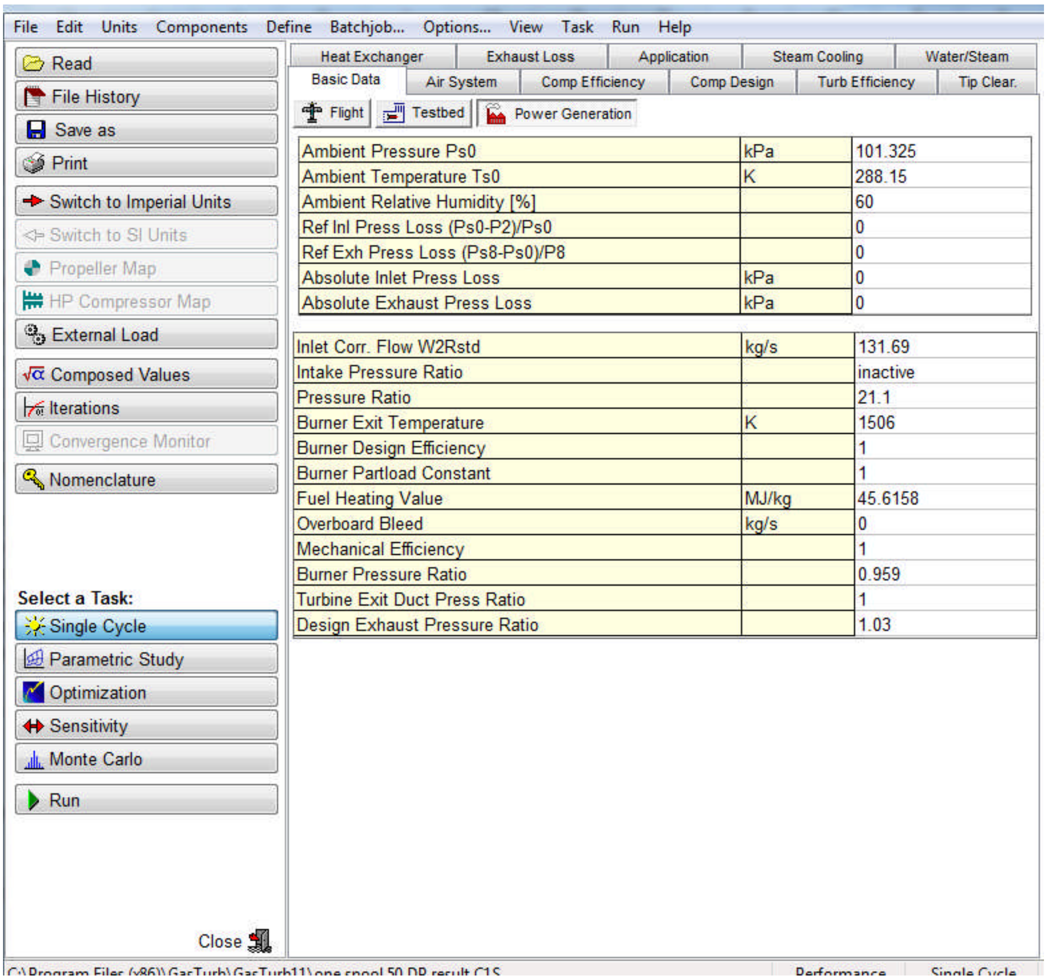
hum [%] war0 FHV Fuel

60.0 0.00637 49.736 Natural Gas

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\80MW range dp.C1S

Engine 4



	W	T	P	WRstd			
Station	kg/s	K	kPa	kg/s	PWSD	=	50478.7 kW
amb		288.15	101.325				
1	131.438	288.15	101.325		PSFC	=	0.2031 kg/(kW*h)
2	131.438	288.15	101.325	131.690	Heat Rate=		9265.5 kJ/(kW*h)
3	131.438	740.81	2137.957	10.007	Therm Eff=		0.3885
31	131.438	740.81	2137.957		WF	=	2.84812 kg/s

4 134.286 1506.00 2050.301 15.291

41 134.286 1506.00 2050.301 15.291 s NOx = 0.62872

49 134.286 825.78 104.365 incidence= 0.00000 °

5 134.286 825.78 104.365 222.442 XM8 = 0.2108

6 134.286 825.78 104.365 A8 = 2.6581 m²

8 134.286 825.78 104.365 222.442 P8/Ps8 = 1.03000

Bleed 0.000 740.81 2137.953 WBld/W2 = 0.00000

-- P2/P1 = 1.00000

Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies: isentr polytr RNI P/P W_NGV/W2 = 0.00000

Compressor 0.8500 0.8978 1.000 21.100 WCL/W2 = 0.00000

Burner 1.0000 0.959 Loading = 100.00 %

Turbine 0.8900 0.8472 2.931 19.646 e45 th = 0.89000

Generator 1.0000 PW_gen = 50478.7 kW

Spool mech Eff 1.0000 Nom Spd 6608 rpm P6/P5 = 1.0000

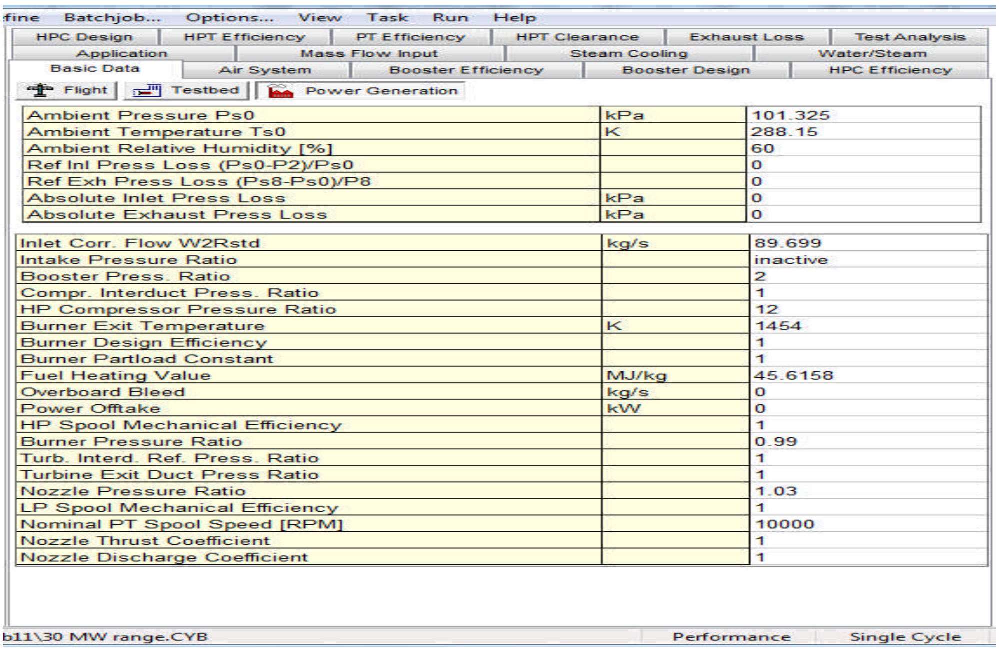
----

hum [%] war0 FHV Fuel

60.0 0.00637 45.616 NAOCAPGNige

Input Data File:C:\Program Files (x86)\GasTurb\GasTurb11\one spool 50 DP result.C1S

Engine 5



fine Batchjob... Options... View Task Run Help

HPC Design | HPT Efficiency | PT Efficiency | HPT Clearance | Exhaust Loss | Test Analysis

Application | Mass Flow Input | Steam Cooling | Water/Steam

Basic Data | Air System | Booster Efficiency | Booster Design | HPC Efficiency

Flight | Testbed | Power Generation

Ambient Pressure Ps0	kPa	101.325
Ambient Temperature Ts0	K	288.15
Ambient Relative Humidity [%]		60
Ref Inl Press Loss (Ps0-P2)/Ps0		0
Ref Exh Press Loss (Ps8-Ps0)/P8		0
Absolute Inlet Press Loss	kPa	0
Absolute Exhaust Press Loss	kPa	0

Inlet Corr. Flow W2Rstd	kg/s	89.699
Intake Pressure Ratio		inactive
Booster Press. Ratio		2
Compr. Interduct Press. Ratio		1
HP Compressor Pressure Ratio		12
Burner Exit Temperature	K	1454
Burner Design Efficiency		1
Burner Partload Constant		1
Fuel Heating Value	MJ/kg	45.6158
Overboard Bleed	kg/s	0
Power Offtake	kW	0
HP Spool Mechanical Efficiency		1
Burner Pressure Ratio		0.99
Turb. Interd. Ref. Press. Ratio		1
Turbine Exit Duct Press Ratio		1
Nozzle Pressure Ratio		1.03
LP Spool Mechanical Efficiency		1
Nominal PT Spool Speed [RPM]		10000
Nozzle Thrust Coefficient		1
Nozzle Discharge Coefficient		1

b11\30 MW range.CYB | Performance | Single Cycle

	W	T	P	WRstd			
Station	kg/s	K	kPa	kg/s	PWSD	=	30188.8 kW
amb		288.15	101.325				
1	89.527	288.15	101.325		PSFC	=	0.1998 kg/(kW*h)
2	89.527	288.15	101.325	89.699	V0	=	0.00 m/s
24	89.527	362.04	202.650	50.272	P25/P24	=	1.00000
25	89.527	362.04	202.650	50.272	P3/P2	=	24.00
3	89.527	789.94	2431.800	6.188	FN res	=	10.38 kN
31	89.527	789.94	2431.800		Heat Rate	=	9111.8 kJ/(kW*h)
4	91.202	1454.00	2407.482	8.683	WF	=	1.67507 kg/s
41	91.202	1454.00	2407.482	8.683	Loading	=	100.00 %

```
 43    91.202   1037.88   452.123              s NOx    =    0.8523
 44    91.202   1037.88   452.123              Therm Eff=   0.39509
 45    91.202   1037.88   452.123    39.064      P45/P44  =   1.00000
 49    91.202    755.11   104.365              P6/P5    =   1.00000
  5    91.202    755.11   104.365   144.347
  6    91.202    755.11   104.365              A8       =   1.72501 m²
  8    91.202    755.11   104.365   144.347      P8/Pamb  =   1.03000
Bleed    0.000    789.94  2431.792              WBld/W2  =   0.00000
-------------------------------------------      P2/P1    =   1.00000
Ps0-P2=  0.000    Ps8-Ps0=   0.000              Ps8      =   101.325 kPa
Efficiencies:   isentr  polytr    RNI     P/P
 Booster        0.8500  0.8638  1.000  2.000      driven by HPT
 Compressor     0.8300  0.8757  1.524 12.000      WHcl/W2  =   0.00000
 Burner         1.0000                 0.990      WLcl/W2  =   0.00000
 HP Turbine     0.8800  0.8568  3.585  5.325      e444 th  =   0.88000
 LP Turbine     0.8900  0.8700  0.990  4.332      eta t-s  =   0.87548
 Generator      1.0000                          PW_gen   =   30188.8 kW
-------------------------------------------
HP Spool mech Eff 1.0000  Nom Spd  34000 rpm
LP Spool mech Eff 1.0000  Nom Spd  34000 rpm      WHDBld/W2=   0.00000
PT Spool                  Nom Spd  10000 rpm      TRQ      =    100.00 %
-------------------------------------------
```

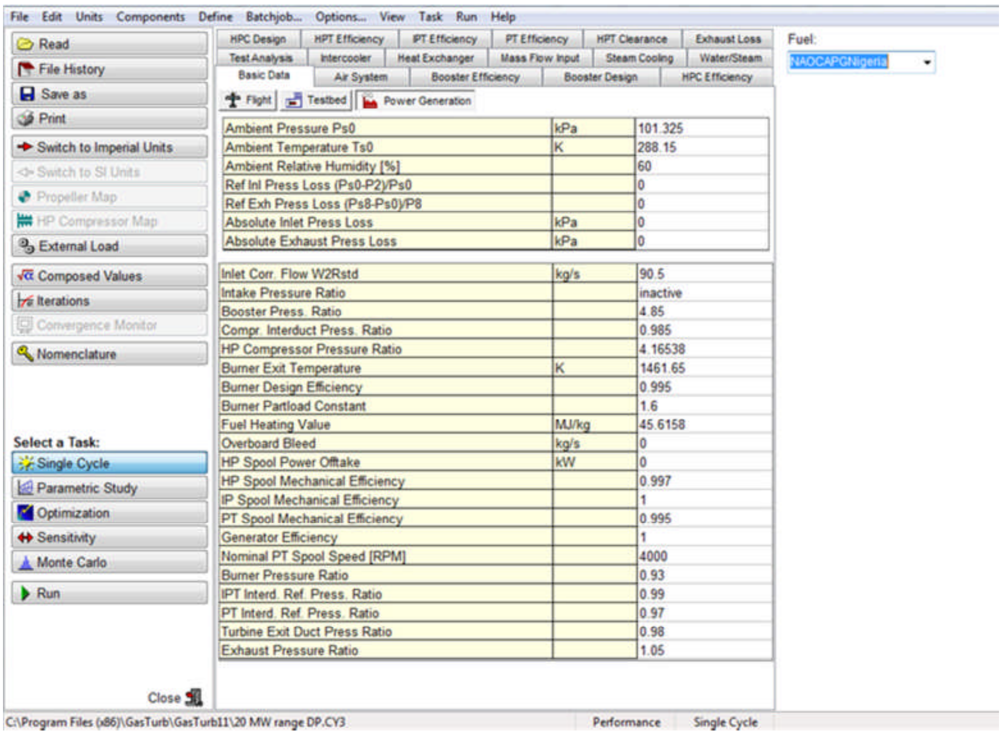
hum [%] war0 FHV Fuel

60.0 0.00637 45.616 NAOCAPGNige

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\30 MW range.CYB

__Engine 6__



Station W T P WRstd

Station kg/s K kPa kg/s PWSD = 27183.6 kW

amb 288.15 101.325

1 90.327 288.15 101.325 PSFC = 0.2170 kg/(kW*h)

2 90.327 288.15 101.325 90.500 P2/P1 = 1.00000

24	90.327	468.30	491.426	23.788	P25/P24 = 0.98500
25	90.327	468.30	484.055	24.150	P3/P2 = 19.89906
3	88.068	730.77	2016.272	7.062	Heat Rate= 9898.6 kJ/(kW*h)
31	79.487	730.77	2016.272		WF = 1.63856 kg/s
4	81.126	1461.65	1875.133	9.948	s NOx = 0.58322
41	85.642	1426.56	1875.133	10.372	Therm Eff= 0.36369
42	85.642	1195.01	801.388		W_NGV/W25= 0.05000
43	88.352	1181.81	801.388		WHcl/W25 = 0.03000
44	88.352	1181.81	793.374		P44/P43 = 0.99000
45	89.255	1176.89	793.374	23.199	WINcl/W25= 0.01000
46	89.255	1024.15	418.391		WIcl/W25 = 0.01000
47	90.159	1020.72	418.391		WLcl/W25 = 0.00500
48	90.159	1020.72	405.840	42.661	P48/P47 = 0.97000
49	90.159	761.43	108.562		Incidence= 0.00 °
5	90.610	760.06	108.562	138.306	
6	91.514	759.79	106.391	142.502	P6/P5 = 0.98000
8	91.514	759.79	106.391	142.502	P8/Pamb = 1.05000
Bleed	0.452	730.76	2016.265		WBld/W2 = 0.00500

-- A8 = 1.34624 m²

Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies: isentr polytr RNI P/P

Booster 0.9020 0.9208 1.000 4.850 WBHD/W2 = 0.00000

Compressor 0.8500 0.8754 2.678 4.165 WBld/W25 = 0.00500

Burner 0.9950 0.930 Loading = 100.00 %

HP Turbine 0.9051 0.8960 2.853 2.340 e442 th = 0.88999

IP Turbine 0.9126 0.9062 2.853 1.896 WlkLP/W25= 0.01000

LP Turbine 0.9057 0.8901 0.906 3.738 eta t-s = 0.86779

Generator 1.0000 PW_gen = 27183.6 kW

HP Spool mech Eff 0.9970 Nom Spd 12000 rpm TRQ = 100.00 %

IP Spool mech Eff 1.0000 Nom Spd 4800 rpm

LP Spool mech Eff 0.9950 Nom Spd 4000 rpm

----

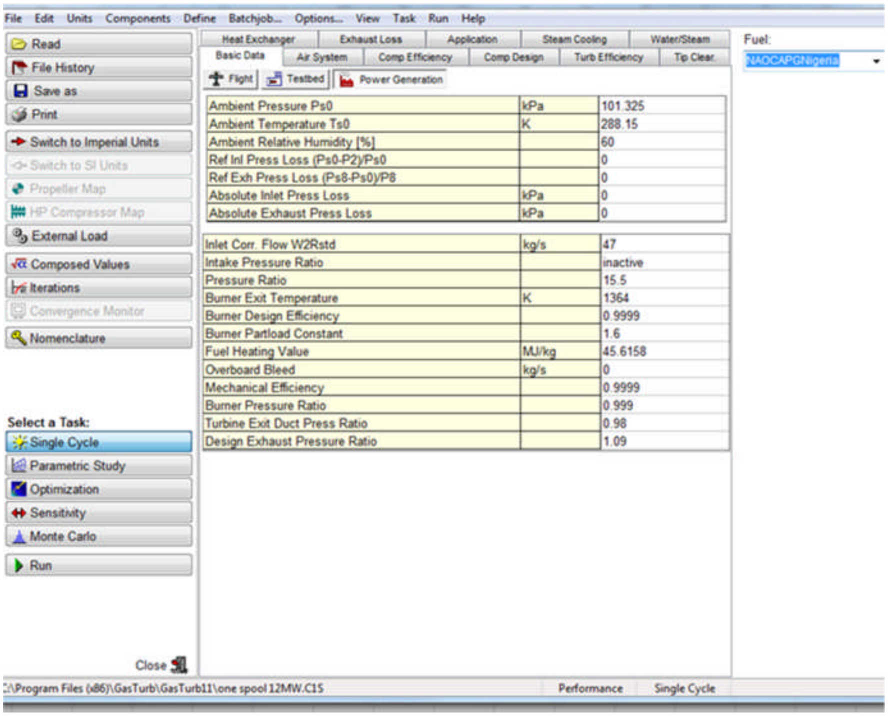
hum [%] war0 FHV Fuel

60.0 0.00637 45.616 NAOCAPGNige

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\20 MW range DP.CY3

Engine 7



	W	T	P	WRstd			
Station	kg/s	K	kPa	kg/s	PWSD	=	11243.7 kW
amb		288.15	101.325				
1	46.910	288.15	101.325		PSFC	=	0.2515 kg/(kW*h)
2	46.910	288.15	101.325	47.000	Heat Rate=		11470.6 kJ/(kW*h)
3	46.910	678.32	1570.537	4.652	Therm Eff=		0.3138
31	41.750	678.32	1570.537		WF	=	0.78538 kg/s
4	42.535	1364.00	1568.967	6.019			
41	44.881	1331.27	1568.967	6.272	s NOx	=	0.40297
49	44.881	770.58	112.698		incidence=		0.00000 °
5	47.226	766.19	112.698	69.690	XM8	=	0.3598

6 47.226 766.19 110.444 A8 = 0.5210 m²

8 47.226 766.19 110.444 71.112 P8/Ps8 = 1.09000

Bleed 0.469 678.32 1570.536 WBld/W2 = 0.01000

--- P2/P1 = 1.00000

Ps0-P2= 0.000 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies: isentr polytr RNI P/P W_NGV/W2 = 0.05000

Compressor 0.8500 0.8943 1.000 15.500 WCL/W2 = 0.05000

Burner 0.9999 0.999 Loading = 100.00 %

Turbine 0.8900 0.8520 2.584 13.922 e45 th = 0.86924

Generator 1.0000 PW_gen = 11243.7 kW

Spool mech Eff 0.9999 Nom Spd 1100 rpm P6/P5 = 0.9800

----

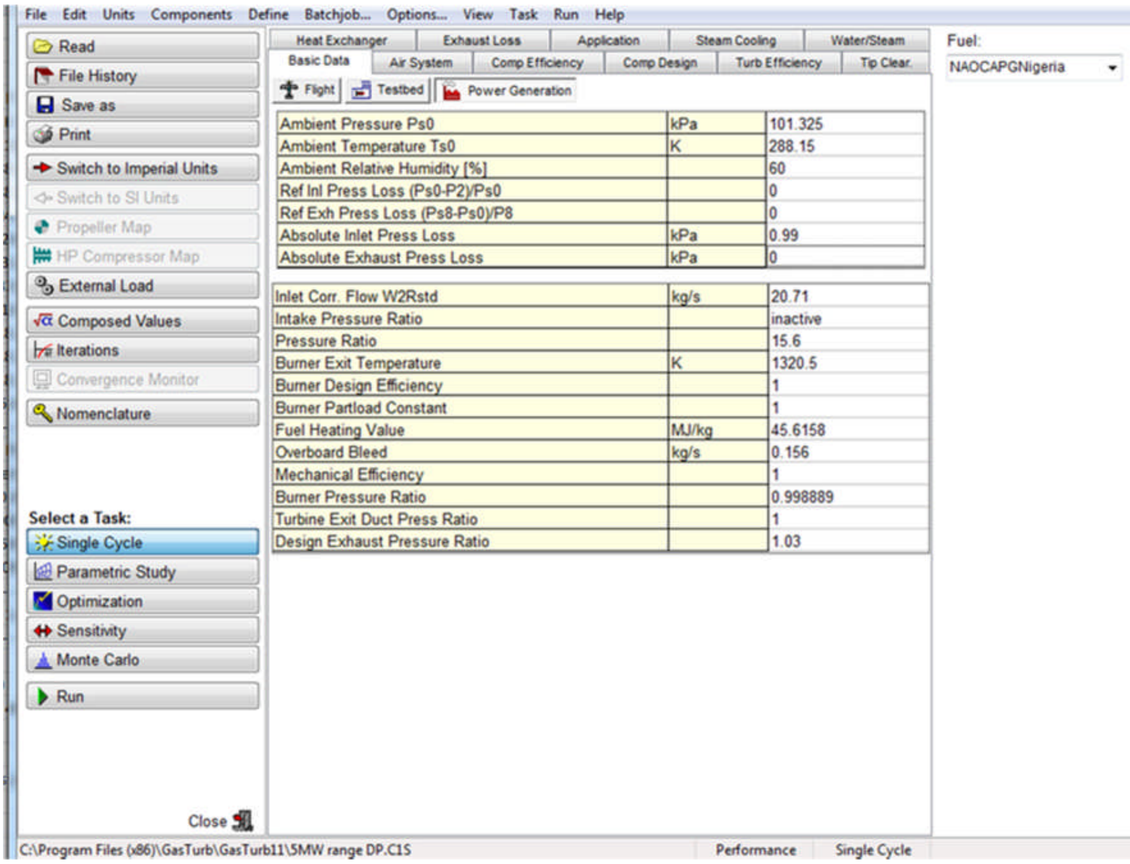
hum [%] war0 FHV Fuel

60.0 0.00637 45.616 NAOCAPGNige

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\one spool 12MW.C1S

Engine 8



	W	T	P	WRstd	
Station	kg/s	K	kPa	kg/s	PWSD = 5030.2 kW
amb		288.15	101.325		
1	20.468	288.15	101.325		PSFC = 0.2509 kg/(kW*h)
2	20.468	288.15	100.335	20.710	Heat Rate= 11443.8 kJ/(kW*h)
3	20.468	686.87	1565.226	2.050	Therm Eff= 0.3146
31	20.312	686.87	1565.226		WF = 0.35054 kg/s
4	20.663	1320.50	1563.487	2.886	
41	20.663	1320.50	1563.487	2.886	s NOx = 0.42052

49	20.663	775.78	104.365		incidence= 0.00000 °
5	20.663	775.78	104.365	33.135	XM8 = 0.2101
6	20.663	775.78	104.365		A8 = 0.3960 m²
8	20.663	775.78	104.365	33.135	P8/Ps8 = 1.03000
Bleed	0.156	686.87	1565.221		WBld/W2 = 0.00762

-- P2/P1 = 0.99023

Ps0-P2= 0.990 Ps8-Ps0= 0.000 Ps8 = 101.325 kPa

Efficiencies:	isentr	polytr	RNI	P/P	W_NGV/W2 = 0.00000
Compressor	0.8340	0.8830	0.990	15.600	WCL/W2 = 0.00000
Burner	1.0000			0.999	Loading = 100.00 %
Turbine	0.8546	0.8057	2.599	14.981	e45 th = 0.85460
Generator	1.0000				PW_gen = 5030.2 kW

Spool mech Eff 1.0000 Nom Spd 17384 rpm P6/P5 = 1.0000

----

hum [%]	war0	FHV	Fuel
60.0	0.00637	45.616	NAOCAPGNige

Input Data File:

C:\Program Files (x86)\GasTurb\GasTurb11\5MW range DP.C1S

Appendix C .1

Table C 1: Simple Cycle Genset Prices (<25.5 MW) [108]

Baseload Rating [kW]	Baseload Rating [MW]	Heat Rate [kJ/kWh]	Thermal Efficiency [%]	Genset Plant Price1 [$]	Specific Plant Price in 2003 USD [$/kW]	Specific Plant Price [£/kW] in 210 GBP
3515	3.5	12913.9	27.9	1500000	426.7	318.0
3950	4.0	12266.1	29.4	1600000	405.1	301.9
4040	4.0	10877.6	33.1	1800000	445.5	332.0
4100	4.1	14907.9	24.2	1230000	300	223.6
5200	5.2	13768.5	26.2	1534000	295	219.8
5250	5.3	11816.6	30.5	2029500	398.6	297.0
5500	5.5	11843	30.4	1950000	354.6	264.3
6200	6.2	13483.6	26.7	1700000	274.2	204.3
6700	6.7	11436.8	31.5	2700000	403	300.3
6750	6.8	11415.7	31.5	2666000	395	294.4
6960	7.0	11658.4	30.9	2700000	387.9	289.1
7910	7.9	11500.1	31.3	2950000	373	278.0
7920	7.9	10919.8	33	3200000	404	301.1
10450	10.5	14053.3	25.6	3750000	358.9	267.5
10760	10.8	12090.9	29.8	3730000	346.7	258.4
10690	10.7	11093.9	32.5	4000000	374.2	278.9
13570	13.6	12122.6	29.7	5930000	437	325.7
13750	13.8	10202.4	35.3	6750000	490.9	365.8
13750	13.8	10408.1	34.6	7000000	509.1	379.4
13750	13.8	10408.1	34.6	7500000	545.5	406.5
15000	15.0	11181.5	32.2	5890000	392.7	292.7
14570	14.6	11626.7	31	6200000	425.5	317.1
14580	14.6	12766.2	28.2	4800000	329.2	245.3
16300	16.3	11848.3	30.4	4050000	248.5	185.2
17000	17.0	11183.6	32.2	5910000	347.7	259.1
17000	17.0	10592.8	34	6665000	392.1	292.2
18000	18.0	10144.4	35.5	7950000	441.7	329.2
20000	20.0	10518.9	34.2	5500000	275	204.9
22450	22.5	9912.2	36.3	9500000	409.8	305.4
22800	22.8	9790.9	36.8	9175000	402.4	299.9
24770	24.8	10534.7	34.2	7495000	302.6	225.5
25360	25.4	10281.5	35	7900000	311.5	232.1
25490	25.5	9442.7	38.1	9725000	381.5	284.3

1 Price of equipment only for skid-mounted single fuel gas turbine, electric generator, air intake with basic filter and silencer, exhaust stack, basic starter and controls, conventional combustions systems unless otherwise designated as DLE (dry low emission). Quote FOB the factory in 2003 US dollars.

Table C 2: Simple Cycle Genset Prices (>25.5MW) [108]

Baseload Rating [kW]	Baseload Rating [MW]	Heat Rate [kJ/kWh]	Thermal Efficiency [%]	Genset Plant Price1 [$]	Specific Plant Price in 2003 USD [$/kW]	Specific Plant Price [£/kW] in 210 GBP
27500	27.5	10652.9	33.8	7563000	275	204.9
29200	29.2	10164.4	35.4	8300000	284.3	211.9
29060	29.1	10001.9	36	8490000	292.2	217.8
28775	28.8	9732.9	37	8900000	309.3	230.5
29500	29.5	9527.2	37.8	9600000	325.4	242.5
30980	31.0	9258.1	38.9	9500000	306.7	228.6
32120	32.1	9157.9	39.3	10300000	320.7	239.0
39620	39.6	11299.6	31.9	10100000	254.9	190.0
42300	42.3	9928.1	36.3	11250000	266	198.2
43000	43.0	9722.3	37	11830000	275.1	205.0
49500	49.5	11025.3	32.7	12400000	250.5	186.7
51350	51.4	9379.4	38.4	14800000	288.2	214.8
51920	51.9	8535.4	42.2	16200000	312	232.5
57000	57.0	10656.1	33.8	16100000	282.5	210.5
67400	67.4	10307.9	34.9	15900000	235.9	175.8
70140	70.1	10529.5	34.2	17350000	247.4	184.4
75900	75.9	10297.3	35	18600000	245.1	182.7
85400	85.4	10993.7	32.8	16600000	194.4	144.9
116500	116.5	10603.3	34	19700000	169.1	126.0
120500	120.5	10381.7	34.7	19900000	165.2	123.1
159400	159.4	10497.8	34.3	24700000	155	115.5
169200	169.2	10307.9	34.9	27100000	160.2	119.4
165100	165.1	10086.3	35.7	27400000	166	123.7
171700	171.7	9938.6	36.2	31250000	182	135.6
190700	190.7	10191.8	35.3	30200000	158.4	118.0
189500	189.5	9696	37.1	31650000	167	124.5
255600	255.6	9759.3	36.9	40900000	160	119.2
270300	270.3	9421.6	38.2	43200000	159.8	119.1
265900	265.9	9326.7	38.6	42300000	159.1	118.6
271000	271.0	9305.6	38.7	44720000	165	123.0

1 Price of equipment only for skid-mounted single fuel gas turbine, electric generator, air intake with basic filter and silencer, exhaust stack, basic starter and controls, conventional combustions systems unless otherwise designated as DLE (dry low emission). Quote FOB the factory in 2003 US dollars.

Appendix C.2 Natural Gas Wellhead Price

Table C 3: US Monthly Wellhead Natural Gas Price from 2000-2010 [EIA]

Date	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	U.S. Natural Gas Wellhead Price (Dollars per Kilogram)*										
Jan	0.12	0.31	0.11	0.20	0.24	0.26	0.36	0.26	0.34	0.21	0.26
Feb	0.12	0.23	0.10	0.23	0.23	0.26	0.31	0.31	0.36	0.17	0.24
Mar	0.12	0.20	0.11	0.32	0.23	0.27	0.29	0.30	0.39	0.15	0.21
Apr	0.13	0.21	0.13	0.20	0.23	0.30	0.29	0.28	0.40	0.14	0.19
May	0.14	0.20	0.13	0.22	0.25	0.28	0.28	0.31	0.45	0.15	0.19
Jun	0.17	0.17	0.13	0.25	0.26	0.28	0.26	0.30	0.47	0.15	0.19
Jul	0.17	0.15	0.13	0.23	0.26	0.31	0.27	0.28	0.49	0.16	0.20
Aug	0.17	0.15	0.13	0.20	0.25	0.29	0.30	0.26	0.37	0.15	0.20
Sep	0.19	0.13	0.14	0.21	0.23	0.41	0.28	0.24	0.31	0.14	0.17
Oct	0.21	0.13	0.15	0.20	0.25	0.47	0.23	0.26	0.26	0.17	0.18
Nov	0.20	0.16	0.16	0.19	0.28	0.45	0.31	0.29	0.24	0.19	0.19
Dec	0.26	0.16	0.18	0.22	0.27	0.41	0.31	0.31	0.27	0.21	0.21

* the wellhead gas price in Dollars per Thousand Cubic Feet is converted to Dollars per Kilogram, taking gas density as $22.0 g/ft^3$